JOINT COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)
	) Docket No.
Preparation of the 2007 Integrated Energy Policy Report (2007 IEPR)	) 06-IEP-1F
	)
	)
In-State and Interstate Transmission and Potential In-State Corridors	)
	)

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

MONDAY, MAY 14, 2007

9:33 A.M.

Reported by:
Peter Petty
Contract No. 150-04-002

COMMISSIONERS PRESENT

Jackalyne Pfannenstiel, Chairperson
Presiding Member, IEPR Committee

Jeffrey D. Byron, Presiding Member, Electricity Committee

John L. Geesman, Associate Member, IEPR Committee and Electricity Committee

ADVISORS PRESENT

Melissa Jones

Kevin Kennedy

STAFF PRESENT

Mark Hesters

Jim Bartridge

Jim McCluskey

ALSO PRESENT

Scott Cauchois
Western Electricity Coordinating Council Committee

Tom Flynn
Laurence Chaset
California Public Utilities Commission

Rex Wait
Nevada Hydro Co., Inc.

Dave Geier
San Diego Gas and Electric Company

Ben Morris
Pacific Gas and Electric Company

Jim Beck
Transmission Agency of Northern California

ALSO PRESENT

Ed Chang
Bay Area Municipal Transmission Group, BAMx

Randy Howard
Los Angeles Department of Water and Power

Nam Nguyen
Southern California Edison Company

J. Richard Lauckhart
Global Energy Decisions

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Joe Eto
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James C. Feider
Redding Electric Utility
Transmission Agency of Northern California

Gary DeShazo
California Independent System Operator

Jane Turnbull
League of Women Voters

I N D E X

I N D E X

P R O C E E D I N G S

9:33 a.m.

PRESIDING MEMBER PFANNENSTIEL: Good morning. This is the Energy Commission Joint Committee workshop on instate and interstate transmission and potential instate transmission corridors.

I'm Jackie Pfannenstiel; I'm the Energy Commission Chair and the Presiding Commissioner on the Integrated Energy Policy Report Committee. To my left is Commissioner Byron, who is the Presiding Commissioner on the Electricity Committee. And this workshop is joint between the two Committees. To my right is Commissioner Geesman, who is a Member of both of those Committees. And to his right is Melissa Jones, his Staff Advisor. And to Commissioner Byron's left is Kevin Kennedy, his Staff Advisor.

With that, unless either of the Commissioners have some introductory comments, why don't we move right into the agenda. It's a pretty packed day. We'll have to move pretty expeditiously to get it all in.

MR. HESTERS: We do. We're going to have to keep sort of clicking along.

PRESIDING MEMBER PFANNENSTIEL: Check your mike, that your mike's on?

MR. HESTERS: I think it's on, sorry. I just have to be closer, I guess.

To start with, good morning everyone. We have these housekeeping items that we need to start with.

First of all, restrooms, if you're unfamiliar with them, are out the doors and to the left. You'll see them on your right. If you need to get coffee or any snack food, up the stairs you'll see a white awing, and that's the Rendezvous Cafe.

Lastly, if there's a fire alarm or some other form of alarm, head out the front doors and we will assemble at the park across the street.

This workshop is being both webcast and put on our Webex system. To follow along with the webcast, we have -- I'm not going to run through these web addresses, it's way too complicated. But they're up on the screen.

The first one, just in case you're on the phone is www.energy.ca.gov/webcast/. Just to run through some background on the Webex because it's a fairly new system for us, and we're working

through it, and it may be new for you on the other side, as well.

You can register for the Webex. And as you register you'll get an email back that basically gives you a log-in for it. If you -- there's a whole series of things. It sort of seems screwy to do this right now because if you can't see it here, you can't really be doing it. So, hopefully you're following the webcast and you're online and know how to do it.

If you want to participate by phone because you're having trouble with the webcast, the phone number is 1-866-469-3239 with a passcode of 922071207.

We're encouraging participation in today's workshop. The order of participation is first we'll be taking questions from the dais; then we'll be taking questions from people physically here at the workshop; then we'll be taking questions from Webex.

The way you do that through Webex is there's a raised-hand feature or function on the Webex. If you click that we will be aware that you want to ask a question; and you will be individually unmuted to speak.

And for the phone-only participants, once we've done the other three we'll unmute you as a group and ask you to speak one at a time.

Just a quick overview of the IEPR and strategic plan schedule. The IEPR is on the left; the strategic plan is on the right. We're still holding IEPR workshops through July. Both draft reports -- this is the final strategic plan workshop. Both drafts are due by August 24th.

We'll then be holding hearings in September. The IEPR hearings are scheduled for September 13th and 17th. The strategic plan hearings are scheduled for September 5th.

We then have October target dates for publishing final reports with adoption on October 24th at the business meeting.

And there's a series, this last slide is a series of contacts for the overall proceeding.

Okay, I'm going to start on sort of a brief overview of the filings we got, transmission submittals. And present some background on the transmission projects that we identified in the 2005 Strategic Investment Plan.

First of all, workshop overview for today we have -- it's broken into essentially

three sections. In the morning we're doing instate transmission projects, which is what I'm presenting as an overview.

Then we're going to have a short presentation on the Lake Elsinore advanced pump storage project. And then we're going to have a panel where we have, you actually can see the nametags up on the table there. We are going to be running through a panel where we're asking panel members to identify projects that they think should be included in the Strategic Investment Plan.

One note on the panel is in order to make it go a little bit faster it's not an interactive panel. Mostly we're asking people to make the presentation. I imagine there will be questions from the dais, but we're not looking for conversations back and forth. If that's the case we wouldn't be leaving here today. So that's the first part of the morning.

And the second part of the morning we're focusing on corridors. And the corridors needed for the projects identified earlier. We'll have a short presentation by Jim Bartridge, and then the same panelists, and any others, will make again a

short presentation on corridor needs.

The afternoon is then focused on interstate transmission issues, the projects, and barriers to those projects.

Okay. Our 2005 strategic plan recommended five projects. These were the Palo Verde-Devers 2 500 kV project sponsored by Edison, the Tehachapi Regional Transmission project. That should be phase 1; the phases and segments are about as confusing as anything I've ever seen on a project.

The Sunrise Power Link, sponsored by San Diego Gas and Electric. The Imperial Valley transmission upgrade, and the TransBay cable project, which we have PG&E as the sponsor; mostly that's just in PG&E's area.

Just a brief summary of where the Palo-Devers 2 line stands. It received a certificate of public convenience and necessity from the California Public Utilities Commission in January of this year. They're still awaiting a decision on the Arizona portion, though it's expected in the next couple months.

For the Tehachapi Regional Transmission project, first phase -- there were three segments

of that phase, and all three of those segments received the CPCN approval from the Public Utilities Commission in March of this year. Edison is expected to file on the remaining four to seven segments, segments 4 to 11. It's not a set target; it's a changing project. But we expect to have it further defined once that filing is made by Southern California Edison.

The Sunrise Power Link filed an application with the Public Utilities Commission. It was deemed complete on September 8th of 2006. We're expecting a -- current schedule says there'll be a decision on the CPCN by January of 2008. There's a lot of issues around that project, though.

The Imperial Valley transmission upgrade. We identified phase one of the Imperial Valley; it was the Greenpath project at the time. It included a sort of feeder system for resources in the Imperial Valley area.

This project has mostly disappeared in the coordination and controversy and sort of permitting for the Sunrise Power Link and the Greenpath North. We haven't seen much more on that part of the project.

The TransBay Cable project requires three more permits, two from the City and County of San Francisco, and one from the San Francisco Bay Conservation and Development Commission. We're still expecting an online date of that around summer of 2010.

Okay. At the end of January we adopted forms and instructions for transmission data responses. We received data responses from, as you can see, quite a number of transmission owners. Several of them, the ones you see on the right side that say N/A, mostly we got short descriptions of their transmission systems with an explanation of why either they weren't under our authority or they weren't expanding their transmission system because they weren't having much load growth or didn't have any need to expand their transmission system.

These other filings all have potential -- mostly have potential projects that could be included in the Strategic Transmission Investment Plan. And that is actually what I'm going to go through next.

The Energy Commission is required to adopt the strategic plan, it's the Strategic

Transmission Investment Plan, every two years. PRC section 25324 runs through what's supposed to be included in that plan.

On the transmission side you basically have three transmission -- potential transmission -- what I want to say -- needs, ways to say a transmission project is needed. One of them is to insure reliability; another is to relieve congestion; and the other one is renewable resources and energy efficiency. But it's sort of other state policy goals.

It's general enough that most transmission projects could fall under those categories. We have earlier -- we refined this to sort of set a limit on the projects that we were going to consider for the Strategic Investment Plan.

These refinements go as follows, as you can see on the next slide: We still have the same in the legislation, insure reliability, relieve congestion, meet future load growth, provide access to renewable resources.

Other strategic benefits, and we spent quite a bit of time discussing what other strategic benefits were in the 2005 Strategic

Transmission Plan.

Those include things like reducing the impacts, or preventing high-cost, low-probability events, which we call sort of an insurance benefit. Helping assist with other state policy goals. And those state policy goals, an example of that would be the policy to see the older oil and gas plants retired by 2012. There were several others, but those are the sort of main ones that show up.

Last time in the 2005 plan we limited projects to those projects that were needed five years past the adoption of the strategic plan. So that limited projects with projected online dates of 2010. This time we're expanding it to ten years. Partly because it's taking longer -- not taking longer, but because some of the projects are large projects, and they're taking more time to permit and to plan. And we need to look farther out.

There's also a series of regional projects. The interstate projects that, because of their complexity, which we will discuss in the afternoon, they're actually again something that needs a longer timeframe to look at.

And the other reason to look longer is because of the recent legislation that is letting us designate corridors. And partly corridor needs need to be looked at longer than five years.

And the final criteria actually is one that turns out to be one of the most limiting. And that is that it requires permitting approval. We'll find that in a lot of the filings, -- the PG&E filing includes over 50 project. But a lot of those are reconductoring projects and projects that are improving the system within substations. And they don't really require major permitting approval.

If we've missed some, we're hoping that representatives today will point those out. But the requiring permitting approval actually is one of the biggest filters for transmission projects.

So, out of the filings that we got -- we received, these are the filings that included projects that we believe should be, or could be included, are actually candidates for the Strategic Investment Plan.

For Edison we had five projects. We did get some complaints, including the Lake Elsinore Advanced Pump Storage project be cut here, because

Edison isn't the sponsor for that project. But it was included in their filing. That's why it's here. We know that they're not the sponsor for that project. And we do have representatives of the LEAPS project here today, and they will be speaking after I finish.

So, Edison projects that are candidates for the strategic plan. The first one I have is the Tehachapi Regional Transmission Plan, segments 4 through 11. As I said, earlier segments 1 through 3 were -- received their permits and -- or at least from the state level in March. This is the further development of the Tehachapi region is a candidate.

The other one, this one I'm hoping to get some clarification from Edison on today. There is the west of Devers upgrade, 230 kV upgrades. These were actually included in part of the application for the Devers-Palo Verde 2 project. Because of permitting issues that was changed to a -- or it was essentially replaced with a second Devers Valley 500 kV line.

I haven't heard whether the west of Devers upgrades have essentially been replaced with this Valley Devers 500 kV line.

Another one, this Vincent Miraloma 500 kv line. This helps deal with some of the south -- congestion problems in Edison. It's also included as part of the Tehachapi regional plan as one of the later segments.

There's also the Devers-Mirage 230 kV line. It actually, you can see these are occurring in a lot of the same places. It's the eastern side of Edison's system.

And then, again, there's the Lake Elsinore project.

PG&E had three projects that showed up, that stood out, actually, as we went through their filing. There's the Gates to Gregg 230 kV line; and the Midway-Gregg 500 kV line, which are - -the Midway/Gregg line actually would replace the need for the Gates/Gregg line.

And both of these are essentially allowing power to move into the Fresno area. And they do two things. They increase the load-serving capability in Fresno, but they also increase the pumping window for the Helms Pump Storage Plant. And this could be a critical need as we start adding renewable or non-schedulable resources in California.

Allowing a greater window for pumping at Helms Pump Storage may allow us to take a better advantage of the energy that we can't schedule, and use it more onpeak.

And finally PG&E had a mention of a 500 kV substation that's being studied in their Greater Bay Area study group. We are expecting -- actually I spoke with Ed Chang some this morning, and he is going to provide a little bit more on that as part of this -- a little bit more on the substation needs and the Bay Area development.

From LADWP we had two projects that jump out at us. One of them was the Greenpath North, which is basically tying IID and LADWP together. And the other one was a LADWP/Tehachapi transmission project which would bring power from the Tehachapi region into the LA service area.

The other one that we didn't include in Edison's filing was an upgrade of the dc line between the Intermountain Power project and LA; partly because that appears to be just a substation increase. It brings significant capacity into California, but it didn't appear to need permitting.

And then we have the TANC filing, the

Transmission Agency, which had a project something like the LADWP project which was this California/Oregon Intertie upgrade. But again that appeared to be mostly within the substation. A good project for California, but not meeting the criteria of the permitting the way it's set down.

TANC had -- or the Transmission Agency had five projects. They were labeled the alpha, beta, delta and epsilon. The TANC representative will hopefully expand on these later when we get to the panel.

They do various things connecting the various TANC members together; bringing and connecting their resources.

And then we had three -- well, three last. We had SMUD, which had the O'Banion/Elverta; it's a 230 kV line that's a double circuit line. One circuit connects to the Elverta; the other connects to the Natomas/Broad substation. It's a 230 kV project.

It's an interesting project partly because I know we don't have a SMUD -- at least I was informed we didn't have a SMUD representative, so I will expand a little bit on this one.

One of the things it does is it reduces

the need to use special protection systems on the Sutter Energy Center, which actually means that so when lines are out you don't have to back down generation from the Sutter Energy Center as much. Which is sort of a side bonus of the project. It also tends to relieve some of SMUD's worst contingency overloads.

Then there's the Modesto Irrigation District Westley-Rosemore line, and the Turlock Irrigation District's Westley-Marshall lines.

I think that's the extent of the projects. We've identified -- there's actually 18 there. One of the ones that was there was the Sunrise project, but because we bumped that to the summary from before, it's not in that list.

Many of the projects still require a lot of definition. And as part of putting together the Strategic Investment Plan, we will go through and review reports and publications and everything that's available on these. And provide a detailed summary of the projects.

Just a couple of notes on the studies is that the studies don't appear to address certain state policy goals. The one that jumps -- that is pretty apparent to me is the aging gas generator

policy. There don't appear to be any projects that deal with that.

It could be that that hasn't been incorporated into the planning process, and needs to be. Because actually the policy was that these should be retired by 2012. And as we get closer to 2012 it gets harder to do.

The other one is there's little or no discussion of nontransmission alternatives. Most of the submittals are essentially annual reports. Understanding that part of the way that the transmission planners and the transmission owners deal with the uncertainty of generation is by doing the studies annually. That covers some of the generation and other uncertainty, or possibly, essentially nontransmission alternatives. If generation comes in and it bumps the need for a project, they will remove the project. But, again, we don't see much discussion of nontransmission alternatives.

And I think that was it. Any questions? Any questions from the room? And any questions from Webex? I'm just going to run through this list. No questions. Any questions on the phone?

Thank you.

MR. WAIT: Well, good morning, Commissioners and CEC Staff. My name is Rex Wait; I'm with Nevada Hydro Company. I'm here for a brief presentation on the Lake Elsinore Advanced Pump Storage project and the 500 kV interconnection.

I'll try to make this brief today because you guys have a pretty full agenda. So maybe what I'll do is kind of rapidly go through the PowerPoint; maybe hold questions towards the end if that's acceptable with everybody here.

Okay, the LEAPS project. It is one project and it is two projects. Obviously the Nevada Hydro Company is one of the sponsors. The Elsinore Valley Municipal Water District, the California muni is our co-applicant.

The project is a 500 megawatt pump storage unit. It stores about 6000 megawatts per day. It's also regional 500 kV interconnection project between Edison and San Diego. Largely the storage source is going to be renewables, and we'll get into that a little bit as we go along.

Again, it is part of a large 500 kV backbone, and we'll show you some transmission diagrams that kind of just shows you what we're

trying to do regionally. We're in the final throes of our permitting so we're looking at a very late 2007 construction start date.

This is a critical asset. It's both the pump storage unit and the transmission facility are located within DOE's draft critical congestion area. It promotes, actually quite a bit, with RPS and greenhouse gases, because it is pump storage, so we have a choice of a lot of different forms of power to store in this, including wind and different forms of renewables.

It is a complementary project to Sunpath; and you'll kind of get an idea as we go along with the transmission paths how the two projects fit together.

It's about 30 miles long. The power line is designed at 1600 megawatts thermally; 95 percent of this project is in public lands. It will likely be the only 500 kV link from the north from Edison into San Diego at 500 kV.

We are linked to different forms of renewables, both Tehachapi and also potentially some of the Palm Springs land. Our system impact studies have been done; the project's been looked at; various different planning studies by the

California ISO. And we do have a joint FERC/ Forest Service final EIS out.

This diagram here kind of gives you an idea of what we're doing. To the north is SCE, 30 mile transmission. We have phase shift devices so we can bidirectionally control flow on this link to and from Edison and San Diego. And we're connecting at 230 kV to the south.

This is a larger map and you can kind of see the dotted area to the lower left. That's the LEAPS project. And, of course, with the long-term ISO plans what we're attempting to do is to complete a 500 kV loop to the south into San Diego.

Again, construction can commence late 2007. We've had independent needs determinations done by FERC. It's largely supported by the federal agencies. We will provide 1000 megawatts of reliability into San Diego by 2009.

Again, we're linked to various forms of renewable energy. The cost of this transmission line is $350 million without the pump storage. We'll reduce obviously RMR in San Diego, LCR in Los Angeles, we reduce MCPs in California. And, again, we've talked about the renewables.

This is a closed loop pump storage. This will be the first new hydroelectric license that FERC has issued in close to 20 years. This is a very rapid, high response pump storage. It's 83 percent efficient at the 500 kV level. So that means for every kilowatt we get 83 percent back. It's dispatchable in 15 seconds. And it can operate black-start and continuous in emergency mode for 18 hours.

The permitting. Basically you can see we're pretty well down to the end. We just have our CEQA to complete.

And most everybody here understands the benefits of pump storage. It goes way beyond the use of energy. We provide a full range of ancillary services, black start, regulation; in some cases we can provide energy and ancillary simultaneously.

The project has also been identified under the EPA Act of 2005. This is advanced transmission technology. Again, some more benefits of pump storage.

The LEAPS facility, again you saw the transmission component was about 350 million. The LEAPS facility, itself, is about 750. The ISO

under CTSRP found about 150 million-plus in annual benefits of the pump storage. Obviously a lot of the benefits come from ancillary services and the wind integration.

Workshop guidelines. This is interesting. We were kind of reading and backing into what the CEC's efforts are. Certainly this project is needed by 2017 to insure reliability. We do have to complete our CEQA effort. And we will have to apply for a CPCN on our two transmission connections and upgrades in the Edison and San Diego systems.

We are part of a broader corridor that was linked through the U.S. Forest Service with section 368.

Again, we talked about relieving reliability and congestion access to renewables. Again, this is becoming a near-term project. You know, we hope to finish our CEQA and our 401. We talked about the renewables and the reduce of greenhouse gases.

This project is a -- because 95 percent of it is on public lands, unlike the Valley-Rainbow, we are a public alternative in a use of forest lands for a transmission corridor. We do

have 5 percent on private lands. So this project is very similar to the Valley-Rainbow effort, only nine miles west in the Cleveland National Forest.

It was identified by the DOE as part of the National Electric Interest Transmission Corridor Act, again with the 368. We're in that application, as well. And, again, our right-of-ways are in public lands, largely. And, again, we are attempting to link, you know, the Southern California Edison system down to the San Diego system.

So with that I'd like to open this to any questions.

ASSOCIATE MEMBER GEESMAN: Rex, is the transmission component of the project severable from the pump storage?

MR. WAIT: Yes, it is. It's kind of awkward, but we have really two projects. Under FERC they're presently licensing a transmission project and a pump storage; and separately we've applied to the U.S. Forest Service for a transmission-only project.

ASSOCIATE MEMBER GEESMAN: Thank you.

PRESIDING MEMBER BYRON: Mr. Wait, you had indicated the storage capability, I think you

said 6000 megawatts per day? Was that megawatt hours per day?

MR. WAIT: Yes, 6000 is the nominal megawatt hours per day. It has an emergency capacity of about 8000.

PRESIDING MEMBER BYRON: And could you just explain, I'm not following the distinction between the 500 megawatt capability and then a couple other slides talked about 1000 megawatt capability. And I'm not sure I'm understanding those two.

MR. WAIT: Oh, I'm sorry. The powerline is rated at 1000 megawatts, or the path is. So the transfer capability to San Diego is at 1000; 500 of that being from the LEAPS facility. I'm sorry. It's a little confusing.

And then as far as the math goes on this, we can keep it pretty easy. The efficiency is 83 percent, so it generates at 500, pumps at 600. So 500 divided by 6 is 83. So it pumps and generates in an hour square. So as far as its capacity on a nominal basis, it's 12 hours at 500 megawatts of generation. And then it can, on an emergency basis or black-start basis, go up to 18 hours.

PRESIDING MEMBER BYRON: Okay. And a couple of times you mentioned that attempting to do an interconnection with SCE. Could you explain, is there some difficulty with that? Or is that -- can you explain what you mean by attempting to do an interconnection with SCE?

MR. WAIT: I'm sorry, I probably misspoke a little bit. We're completing our interconnection facility studies and LGI agreements with Edison presently. So we'll be looking at a new substation between Valley and Solano at 500 kV. And that substation will be called Lake Sub. It's off of 15, north of Lake Elsinore.

And then the southern connection is similar, only at 230, at Camp Pendleton. And it'll be called Case Springs. And, again, it's a new substation.

PRESIDING MEMBER BYRON: Thank you.

MR. WAIT: Any more questions?

PRESIDING MEMBER PFANNENSTIEL: Just one. Can you help me on your next steps going forward. When are you going to actually start construction? What needs to happen between now and then?

MR. WAIT: That's a great question. Our EPC contractor on this is Siemens. They'll be responsible for turnkey of the subs and the lines. So they've completed their preliminary engineering; they're beginning their final now.

And we're, you know, trying to lock up. As you guys know, transmission components are getting in short supply right now, so we're trying to lock up as many of the long lead items as we can.

So the next steps are completion of CEQA. Then our 401. And then the 401's required to finish up the FERC permit. And then basically we're done.

There's another aspect to this. It's really kind of an independent process. We did apply under a 205 to put not only the transmission but the LEAPS facility under CAC, and we're waiting for that process to come to a close in the next 30 to 60 days.

Thank you.

MR. BARTRIDGE: Were there any questions on the phone? Okay.

MR. HESTERS: We'd actually now like our panelists to come forward. I'm going to shift a

couple of the names because I know that Ed Chang wanted to sort of come after PG&E, and probably have some conversation with TANC, as they go, because their project -- their discussions are somewhat related. So rather than separating them, I wanted to move them together.

(Pause.)

MR. HESTERS: Sorry, when we put those out there we were just trying to get them out there.

Okay, for the panel we're basically going to go around the room starting on my left and working around the table. We basically have two questions we're asking the panel members to answer.

The first one is what projects do you believe should be included in the 2007 strategic plan; and why those projects should be included. And then also what longer term projects are critical, but do not meet the 2017 time horizon for inclusion in the 2007 strategic plan.

We'll start with Dave Geier, San Diego Gas and Electric.

MR. GEIER: Good morning, Madam Chair, Commissioners, Staff. Thank you for inviting us

today.

I will speak today about our long-term needs for San Diego. But I guess I'd like to start with the -- I guess I was a little surprised this morning not to see Sunrise on the list of proposed projects. I'll discuss that as I go into my comments.

I think if you look at sort of the criteria that was laid out, it seems that the Sunrise project meets all or most, if not all, the criteria that we've identified.

But I'll start with, you know, we support the CEC and the staff's recommendation to take the strategic plan out to a ten-year window for infrastructure projects. I think it's clear that with the licensing environment we're in that a five-year window just really doesn't work for the state anymore. So I think looking out ten years for infrastructure projects, and the 20-year look for corridors is definitely the right direction to go.

I'll skip my comments on the corridors; I think we have another opportunity at that. But I guess I am -- I'm happy to report that as of last Friday San Diego put the Otay Metro, a 230 kV

loop, which goes around the City of San Diego and actually through the City of San Diego, in service. And this was a big step forward from a reliability perspective; helps us from congestion.

Also this project was really our first project with 230 kV underground of any significant length. And we have about 10 miles of 230 kV underground. So, it was a big step forward for San Diego.

Our next critical project is the Sunrise Power Loop. I think everybody's aware of the project. You know, first and foremost, it's a reliability project. We need it for reliability for 2010 for San Diego.

Secondly, though, it will help us meet our RPS goals. It's very difficult to see how we can meet those goals without the Sunrise project. And third, it is an economic project. And I was happy to see that other agencies are joining in and really, you know, sort of confirming the need for the Sunrise Power Link. We have the ISO Board approval in the 2005 IEPR project here at the CEC. We know it's specifically mentioned.

DOE, with its transmission congestion study last year, declared San Diego region as one

of the two critical congested areas. And then recently, with the national interest corridors, they've identified southern California as an area of national interest corridors, also. In fact, this Thursday they'll be in San Diego for public hearings.

Now, our team has worked close with the CEC going all the way back to the Imperial Valley study group; and really identified sort of, you know, the diverse renewables that are in the Imperial Valley, and the need really to connect them.

In fact, I think I mentioned a few weeks ago that we currently have over 6000 megawatts of renewable energy in the queue coming out of Imperial Valley and Mexico. A hundred percent of these are renewable. The good thing about them, also, very diverse group of renewables. There's wind, there's solar, small amount of geothermal. I think all the studies have identified that there's, you know, 2000 megawatts of geothermal that's not even on this list.

We really do appreciate this Commission's leadership and recognition of the importance of connecting those renewables to the

load centers. And we encourage this Commission to work closely with the PUC to get swift completion of our CPCN. And the good news is that we've been through a number of the processes. We do have hearings scheduled for July of this year. And we've kept the decision date for January of next year.

So I guess in addition to the long-term work we're talking about today, I think we would request that the CEC take an advocacy role and really help us in the decisionmaking process for the near-term projects, particularly the Sunrise project. And I guess given the fact this morning that we do not see that on the proposed list, I guess I would be asking today to include that in the 2007 plan. And if there's some other reason that we should or need to talk about, we could do that.

In addition to Sunrise there's two other projects that we did not file with -- they weren't really fully developed at the time for the 2007 IEPR process. But there's two projects. One we're calling future 230 kV Orange County transmission. SDG&E serves about 400 megawatts of load in Orange County. It's projected to grow to

700 megawatts in the next 10 to 20 years.

Currently we really only have one 230 kV source to the area. And what this project would propose is to add a second source into the area. There is a 40-year-old substation that needs to be upgraded. And we would propose to bring the 230 kV into that substation.

This does fall in line with our discussion of the existing corridors. There will be a need to use existing corridors.

A second project that has potential in this 2017 timeframe is a new renewable substation tied off our southwest powerlink. This substation with, you know, the recent addition to all the renewables in the queue, would allow another interconnection point to our southwest power link, our SWPPL line for the southeastern part of San Diego County.

Currently we have a number of wind projects. They're sort of on the ridge line going into the desert. Still in San Diego County. And really the only source out in that area now is small 69 kV lines. And with this number of interconnection studies that we have today, it appears we'll need a new substation off of SWPPL

sometime in the timeframe we're talking before 2017.

So, in summary, we do have thousands of megawatts that have been identified in Imperial Valley and east of San Diego. We really do need the CEC's help to continue to help us with the licensing process for Sunrise. And we really do believe that Sunrise fits in right with the goals you've talked about for the reliability point of view; helps reduce congestion; and it does help us link to those renewables for our RPS goal.

Thank you.

MR. HESTERS: I'd just like to clarify real quickly. I didn't mean to leave Sunrise out of the list. It just wasn't a new project from the filings. And I fully expect it will be discussed thoroughly in the 2007 Strategic Investment Plan.

ASSOCIATE MEMBER GEESMAN: That kind of took my --

PRESIDING MEMBER BYRON: Mine, as well.

MR. HESTERS: I'm sorry.

MR. GEIER: Thank you.

MR. HESTERS: And Ben Morris from PG&E.

MR. MORRIS: Good morning, Madam Chair,

Commissioners, ladies and gentlemen. I'm Ben Morris. I work in PG&E's -- I'm Manager of PG&E's Strategic and Technical Services Group. It's basically a transmission planning department.

And I do appreciate the opportunity to speak about PG&E's expansion plans. They're reviewing this and perhaps -- I know that the Energy Commission Staff has reviewed this.

Our expansion plan does contain over $1.5 billion, perhaps as much as $3 billion, depending upon the projects that actually get constructed over the next ten years. So, PG&E is making extensive investments in its transmission system.

One project, though, that was in Mark Hesters' presentation that perhaps I'd like to clarify. It's not technically part of our plan; it's the TransBay Cable project. That project is being proposed by Babcock and Brown.

And I believe the information that Mark Hesters presented in the slides is accurate. They're still awaiting some permitting from the City and County of San Francisco. So we need to wait and see on that, but PG&E is supportive of interconnecting the project, you know, with the

expectation, of course, that it would proceed.

With regard to other major projects, in Mark Hesters' presentation he mentions the Gates-Gregg project. PG&E has actually relabeled this project, and perhaps you'll understand why in a second.

This project now is identified as the Central California Clean Energy Transmission project. It brings all the benefits that Mark Hesters mentioned in his presentation, including better supply to Fresno; more access to renewable power.

It increases the Path 15 south-to-north transfer capability. So, again, it better unifies both the northern and southern portions of the state. It reduces local capacity requirements within the Fresno area. So it does a lot.

It's a pretty big project, of course, 150 miles long. It is costly, but it also brings a lot of benefits to PG&E's ability to meet the RPS requirements.

And as Mark Hesters mentioned, it does defer, assuming this project goes forward, it would defer the need for the Gates-Gregg line indefinitely. So we are looking at roughly a 2012

operative date for the project. And we're currently doing some final analysis of it, and expect to go forward with the permitting process later this year and next year.

ASSOCIATE MEMBER GEESMAN: Would that make use of an existing corridor?

MR. MORRIS: No, it would not. The corridor for this project runs from Midway, heads more or less east out across Edison's Big Creek facilities, up near the Big Creek lines. And into the Fresno area.

We actually do not terminate the project at Gregg Substation, though. It actually would be terminated at a new substation site between Gregg Substation and the Helms Pump Storage.

And I'll explain a little bit later as to a couple of reasons as to why we're not actually terminating the project at Gregg Substation.

The next project I'd like to talk about, it was on Mark Hesters' list, too; it's the Bay 500 kV station. This is but one of the options being considered in a Bay Area long-term study stakeholder group. That group has been doing some work now for the last six months or so. And we've

made, I think, some pretty good progress in terms of the technical studies.

We have numerous options that we've boiled down to approximately five alternatives. And let me just explain here, there's actually Bay Area requires, if we are to minimize the overall cost to customers here, requires several different upgrades, both in the South Bay as well as up near the Delta.

In terms of alternatives that we're looking -- you'll notice here, as I go through this, that the upgrades that we're talking about then both target the South Bay area, as well as the area up around the Delta. So, as I go through this you'll see that.

One of the alternatives involved in the installation of the Bay Area 500 kV station is in the Sunol area. That would be a new 500 230 kV station that would loop off the existing Tesla Los Banos 500 kv line. And there are 230 kV circuits that are right near the proposed substation site that we would loop into and terminate on the 230 kV buss at that new substation.

In addition, we'd be making upgrades of transmission to the north, both out of VacaDixon

all the way down into Pittsburg Substation.

The second option involves upgrades at a new substation site, development of a new substation site called Collins, which is up in the Suisun area. So, again, this is the northern upgrade that I'm talking about right now.

There would be again a 500 230 kV transformer installed at that station, together with 230 kV transmission that would be built over to Pittsburg. We would also make upgrades in the south between PG&E's Tesla Substation in Newark.

The third alternative again involves the same 500 kV Collins Substation to the north with a Tracy/Newark northern receiving station 230 kV line. This is an option that we are studying on behalf of TANC, or with TANC, as part of this Bay Area long-term study.

Fourth option would involve upgrades from VacaDixon down to Contra Costa and into Pittsburg, and also Tesla Newark, and then upgrades to the existing Tracy 500 230 kV station.

So those are the major alternatives that we're looking at here. Again, if these projects are to go forward the driver here is not so much reliability, the driver here is economics.

It's about accessing other resources outside the Bay Area, lower cost resources out of the Bay Area.

And from PG&E's perspective it's going to afford us an opportunity to absorb renewable power coming into the state or within the state by backing off resources in the Bay Area. These are the higher cost resources in the Bay Area that we'd be able to back down. But obviously, to gain access to the renewable resources we'd need to make transmission upgrades to make that happen.

ASSOCIATE MEMBER GEESMAN: You're looking at those five options now as mutually exclusive?

MR. MORRIS: Yes.

PRESIDING MEMBER BYRON: And you're also, if I understood you, you're looking for cheaper upgrades and renewables. So are you equating the two?

MR. MORRIS: I think to gain access to the renewables you need to pay the transmission costs to access those renewables. So, the cost of accessing the renewables is there. We have to go out and get the renewables; contract with them. We also have to get the transmission to them.

But the benefits here is that we would be backing off higher cost resources. And for PG&E's case, our highest cost resources in the system are in the Bay Area. So, by backing off those resources we are going to be able to gain access to renewable power.

So, from using the alternatives I'm looking at here that we're studying, we would be able to achieve both access to renewables outside the Bay Area or beyond, as well as being able to back off the resources within the Bay Area in order to absorb those renewables.

Something that was not in PG&E's expansion plan, and was not part of Mark Hesters' presentation, was another several options that PG&E is looking at. Again, this is a stakeholder process that PG&E is involved in with numerous other entities within northern California.

It's the Northern California Subregional Planning Group. And I just want to spend just a couple minutes talking about that, because there are several different alternatives there that I think will happen. And they're going to have to happen if PG&E is to absorb say power coming in from British Columbia or Canada into northeast

California. It's also going to have to happen if PG&E is to absorb renewable power that might be sited up in northeast California. Or for that matter, simply in the northern reaches of California.

The Northern California Subregional Planning Group is just getting started. It's something that was recently approved by the California Energy Commission. PG&E is in a lead role to do that analysis.

The analysis involves numerous investigation of resource scenarios within the state, within the PG&E service territory, northern California. And what we are after here, the objective would be to identify upgrades that would meet a number of these resource scenarios.

And we believe that there are a couple that are likely to drop out. And I thought I just might talk about those just for a moment. PG&E, together with others, TANC, who's at the table here, and will be speaking to this as well, is investigating bringing in renewable power from the northwest and from Canada.

We've identified a location in northeast California called Raven Substation. It's near the

town of Ravendale up in northeast California. And it's the potential terminus for that project.

The project that we're talking about, and Steve Metague will be speaking to this in more detail this afternoon, we're talking about bringing in upwards of 3000 megawatts from outside the state into this new substation called Raven.

Of course, in order to absorb that level of power in the northeast corner of the state, is going to require significant upgrades to the transmission system. And we've identified, together with TANC and other stakeholders here, upwards of four different alternatives that we're looking at in order to get power from northeast California down into the Bay Area.

And those alternatives, I'm not going to be able to go through the details of them, though there are maps, of course, that are available. But basically two of the alternatives would make use of -- well, one of the alternatives would make use of existing 230 kV corridors from Round Mountain Substation down to Elverta Sub, which is a SMUD substation. And also into PG&E's the Bay Area, that new substation site that I mentioned at Sunol, for example.

A second option would involve 230 kV, you know, being in the same corridor as the 230 kV south of Table Mount. Again, terminating at both Elverta and into the Bay Area.

And then there's a couple of other options that would be more to the east of that, not associated with existing corridors. So separate new corridors that would basically be great to be able to get, because that improves the overall transmission reliability. But it may be at least something we want to investigate and take a look at. So, again, those would terminate at the same locations, both at Elverta and into the Bay Area.

So, these are the -- of course, these upgrades here must coincide with the upgrades coming in from -- that's out-of-state transmission. The British Columbia, Canada Northwest project. We need to be able to get these upgrades in place in order to get that power in from Canada and the northwest.

So, in sum, I again thank you for the opportunity to present some of the plans here. I'll just quickly review, a 30-second review of what I just talked about.

PG&E's got a couple of major projects that it's -- several major projects they're going forward with. They include the Central California Clean Energy Transmission project; that would be a project from Midway to new substation between Gregg and Helms.

PG&E, together with other stakeholders, are looking at upgrades in the Bay Area. One of those alternatives would involve the installation of a new Bay 500 kV station at Sunol.

And then the other major thing that PG&E's involved with is the investigation of alternatives to build transmission from northeast California down to the Bay Area.

So, with that, I thank you for the opportunity.

PRESIDING MEMBER BYRON: Commissioner Geesman, Chairman Pfannenstiel was called away. We hope to get her back soon.

Thank you, Mr. Morris.

MR. HESTERS: Next we have Jim Beck from the Transmission Agency. Please stay up there, Ben. After this we'll have the corridors discussion and it's most of the same people. So rather than having you get up and get down, we'd

appreciate it if you would just stay at the table.

MR. BECK: Thank you, Commissioners, Staff and ladies and gentlemen, good morning. I am Jim Beck; I am the General Manager for the Transmission Agency of Northern California.

For those of you who don't know that agency it is a joint powers agency formed under California law in 1984 to assist its members in developing transmission projects to help meet their future needs and their policy objectives.

Its members include SMUD, Modesto Irrigation District, Turlock Irrigation District, the Cities of Roseville and Lodi in the Sacramento area. The Bay Area cities of Santa Clara, Palo Alto, Alameda and Ukiah and Healdsburg to the north. And the Central Valley cities of Redding, Biggs, Gridley and Lompoc, along with the Plumas Sierra Electric Cooperative.

TANC's publicly owned utilities plan for their reliability, their future needs, and to achieve control of their customers' costs, and to meet the state's policy objectives, such as renewable portfolio standards resource adequacy, reducing carbon emission footprints and tending to retirements of older units, all under the watchful

eye of their locally elected boards and councils.

TANC, as you know, was the developer of the COTP, the California/Oregon Transmission Project, which went operational in 1993. TANC's transmission addition plans being discussed here today are intended to enhance deliverability from the COTP; to increase reliability of the northern California electric system and the intertie with the Pacific Northwest; and to enhance coordination among the TANC members and all of the control areas they operate in. TANC's members operate in these three control areas, the California ISO, the SMUD control area, and Turlock Irrigation District control area.

They will also enhance northern California electric system ability, as Ben has pointed out, to support increased imports and deliverability of renewable resources from the north and the east of California, and from the northern part of the state.

TANC is pleased to comment today in these proceedings, and we will, indeed, as well participate in this afternoon's panel discussing the inter-regional projects and the barriers that may come into play in some of those.

We continue to discuss our plans with those of our neighboring utilities in order to help insure the desired coordination in the region, as is obvious by the amount of conversation that we've had with PG&E with respect to potential common interests. And notably, we're working very closely with them on the projects that Ben pointed out, the Central Valley enhancements and the line into the Delta area.

TANC and its members continue to believe that ownership of transmission assets is critical to their ability to help control their costs and the cost to their customers while satisfying their future resource objectives.

And as I've already mentioned, all of TANC's planned additions are intended to help enhance all of the operations in northern California. And will provide benefits that I've identified on the slides that are included as in my handout.

TANC's projects are cryptically referred to as the Greek letter program elements. And they are alpha, beta, delta, epsilon and zeta. We simply got tired of calling them project number one, two, three and four.

And I will briefly describe them. But, again, in our handout there are pictures of the one-line system diagrams to show the connections. And I do not have that in front of me, frankly. But, -- thank you, I now have it in front of me.

The alpha project is on the east side of the Central Valley. It's north of the area in general where PG&E is talking about its east side improvements. And this project is intended to enhance the tie capability between the SMUD control area and the Turlock Irrigation District control area. And to enhance voltages in the Lodi area generally. One of the difficult areas is in the Central Valley to support voltage.

The beta project strengthens the west side of the Central Valley and ties Turlock Irrigation District to some state and federal generating facilities down around the San Juan Reservoir.

The Delta project is the project that has as its principal purpose, increasing import capability into the South Bay Area from the Tracy/ Livermore area. And it enhances TANC's members potential usage of their COTP transmission line, as well as assisting in the delivery of renewable

resources.

PRESIDING MEMBER BYRON: Excuse me, Mr. Beck.

MR. BECK: Yes, sir?

PRESIDING MEMBER BYRON: I'm just going to check with the staff. Did you bring copies of your presentation --

MR. BECK: Yes, sir, I did.

PRESIDING MEMBER BYRON: Could I just ask if we could have copies up a the dais? That would be very helpful. Do you have -- only if you have extras; I don't mean to take them away from the panelists.

MR. HESTERS: There's one left and we will go make some more this minute.

PRESIDING MEMBER BYRON: Thank you.

MR. BECK: Did bring that electronically, as well, so they are available.

PRESIDING MEMBER BYRON: Thank you. The maps would be helpful. Thank you very much.

MR. BECK: This information, as well, Commissioner Byron, was filed in the IEPR process by TANC on behalf of its members. And so this information, with some better descriptions of the facilities, is also available to the staff.

So I apologize for not having them in front of you.

PRESIDING MEMBER BYRON: Thank you. Please go ahead.

MR. BECK: TANC's epsilon project is a project that would tie the facilities in the San Juan Reservoir area, again down by the McNeil Generating -- state and federal generating facilities to the South Bay Area around the backside, if you will. If we call the frontside going in through the Tracy/Livermore corridor, the backside would come in around through the Gilroy area and into the South Bay.

That project, of course, increases the import capability from the Central Valley to the Bay Area. And would also enhance the reliability of operations in that area.

Finally, TANC's zeta project is a, in its present configuration, a combination of new and upgraded facilities in the Central Valley, running from the Sacramento area, from Tracy area actually, up to, as Ben Morris has described, the Round Mountain area, just northeast of Redding. For the purposes of enhancing deliverability of the COTP. Enhancing deliverability and supporting

deliverability of renewable resources from out of state on one of the couple of projects that TANC is interested in with respect to renewable resources for its members. And will also enhance the reliability of all control area operations in northern California.

And so the central theme for TANC's additions has been to increase their ability to use the assets that they currently own; to enhance the reliability of operations in all of the control areas. And to increase deliverability and imports of renewable resources to its members and to northern California.

All of TANC's plans, to the best of our knowledge, are in addition to the plans of the participating transmission owners in the California ISO, and to other entities who develop plans within the state.

With respect to the questions asked of this panel, and one not asked, first of all, TANC also supports the Commission looking at the ten-year horizon for the strategic plan. These projects take that long in some cases. And inter-regional projects definitely take that long.

We respectfully request that the

Commission consider all of TANC's planned additions for inclusion in the 2007 strategic plan that is being developed through this process. And we request that TANC consider these and all other reasonable plans from other transmission planning entities in the state in support of meeting the local and state policy objectives. And to help stabilize the cost of delivering power to our customers in the state.

With those comments, Commissioners and Staff, I thank you for the opportunity.

ASSOCIATE MEMBER GEESMAN: Jim, have you made those timeframes for these projects available to our staff?

MR. BECK: I believe we did in the filing with the IEPR data. But if we did not, we certainly will do that.

ASSOCIATE MEMBER GEESMAN: And I take it none of these projects are mutually exclusive; they're all projects that ought to be evaluated on their own individual qualities?

MR. BECK: We believe so, Commissioner, yes.

ASSOCIATE MEMBER GEESMAN: And in terms of paying for them, would you envision

apportioning shares among your members? Or would all of your members contribute commensurately for all of the projects?

MR. BECK: I would envision that there would be allocations, but there would be joint participation. Joint action financing is a wonderful thing to see.

PRESIDING MEMBER BYRON: And along those lines, Mr. Beck, is there any -- with the information you provided the staff, is there some timelines associated with these dates?

MR. BECK: With the projects?

PRESIDING MEMBER BYRON: Yes.

MR. BECK: Our current intention is to have the first wave of them done by 2012. And we're very hopeful for that. We know it's a tight squeeze, but we expected to do something with projects alpha, delta and zeta in that timeline. And the rest of the projects would be in the years that follow.

PRESIDING MEMBER BYRON: Thank you, sir.

MR. HESTERS: Now we have Ed Chang from the Bay Area Air Municipal Transmission Group.

MR. CHANG: Good morning. My name is Ed Chang; I'm with Flynn Resource Consultants. I

represent a group that's called BAMx, Bay Area Municipal Transmission Group. They consist of the utilities of City of Palo Alto, Alameda Power and Telecom and City of Santa Clara doing business as Silicon Valley Power.

I spoke before this Commission back in March when we discussed the Senate Bill 1059 about corridors. And essentially my comments then were to encourage corridor leads into highly congested load centers and urban areas; and essentially load centers for accepting additional access to diverse resources.

I'd like to just give a little bit of the background. Ben Morris talked about the long-term Greater Bay Area study group. This is an outgrowth of the San Francisco Peninsula study. My clients, the three cities, have advocated the formation of a study effort to look at the broader needs of the Greater Bay Area. And I'd like to compliment PG&E and the California ISO in doing so. They have initiated a very open process, very participatory process, which in my view meets many of the elements of FERC order number 890 on transmission planning principles. So we ar an active participant of the long-term Greater Bay

Area study group.

I do want to mention that the project that BAMx is supporting is among two, perhaps three, of the elements of the projects that Ben Morris talked about, of the five options for the Greater Bay Area.

Also, the BAMx group have promoted their proposal within the TANC transmission program. Furthermore, BAMx has been working with the Western Area Power Administration; and, in fact, had submitted a transmission service request, and about to finalize that effort, which would obligate Western to perform a certain study, interconnection and study efforts.

So, in terms of what project should be included in the 2007 strategic plan, I'd like to repeat what Jim Beck mentioned about TANC's, the various elements.

By the way, I also want to mention that the project delta that's identified in TANC's handout is one of the elements that's kind of integrated with a number of options in the long-term Greater Bay Area study effort. And the three cities are prepared to step forward to sponsor that project.

However, we wanted to make sure that we provide all the necessary technical study and coordination through the study effort that PG&E and the ISO's involved in right now.

Again, we believe it should be in the 2007 strategic plan. In prior IEPR, or in prior activities this Commission used to have what's called a transmission watch list. We even advocated it at that time. We advocated it in the 2005 IEPR.

This Commission also agreed with the Department of Energy congestion study of last summer, that the Greater Bay Area is a congested area of concern. We plan to report to the Department of Energy in its progress report perhaps this August, late this summer, regarding the status and findings, perhaps preliminary planning, of the long-tern Greater Bay Area study group on this proposal.

That concludes my comments. I'll be glad to entertain questions.

ASSOCIATE MEMBER GEESMAN: Can I pin you down to a more precise date on when your study is likely to be public?

MR. CHANG: The long-term Greater Bay

Area study group schedule, as I saw it last, and correct me, Ben, was year-end. Come this August I don't know what to report to the Department of Energy; perhaps just -- they're initiating some costing studies and estimates. PG&E has larger needs than just the three cities, so -- but that's part of the study effort.

ASSOCIATE MEMBER GEESMAN: Okay, that's helpful; thank you.

MR. HESTERS: I just wanted to say one thing that I hadn't said earlier. We are requesting written comments on the workshop. If you have presentations that we didn't have copies of, to submit those by May 24th.

And we have Randy Howard from the Los Angeles Department of Water and Power.

MR. HOWARD: Good morning, Commissioners, Staff. Randy Howard, LADWP.

LADWP currently owns and/or operates approximately 28 percent of the transmission systems in the State of California. And we have three significant projects that we submitted for the strategic plan.

The Greenpath North project, which I'll discuss briefly here in this panel. Our own

Tehachapi transmission project. So, LA's version. And then the southern transmission system dc line upgrade in which Mark did indicate that according to the criteria listed, that would be excluded from the strategic plan.

I'm going to start with that one first. While it meets all the other criteria, it will not require a permit. And so it would not fall under that category with a permit requirement. It's currently a high-voltage dc transmission line; comes out of the Delta Utah area down into the Victorville, and then into Sylmar. it's currently rated at 1920 megawatts. Our proposed upgrade of that project is an additional 480 to 2400 megawatts.

It fits nicely into some of our RPS goals and objectives. We recently announced a 200 megawatt contract for wind that will feed into the IPP station. We recently signed an agreement for Wyoming wind that feeds into there. And under LA's recent RFP we have several thousand megawatts that have been proposed to come into that area that we would have access to, to bring on down.

That is a joint project with the Cities of Anaheim, Riverside, Pasadena, Burbank and

Glendale. So our expectation is we would have the upgrade completed in late 2008 or early 2009, depending on the outage requirements for the facility there to make the station upgrades. Again, that is just two station upgrades that will not require anything with the line, itself.

So, strategic in nature, but possibly not meeting the criteria for your plan.

PRESIDING MEMBER BYRON: Mr. Howard, what was the name of it, again?

MR. HOWARD: We call it the southern transmission system, STS. You have to have an acronym for pretty much everything.

The other project that we have included is LA's Tehachapi transmission project. And that project would go into an area -- it's an upgrade, about 12 miles northeast of the town of Mojave. We're recently completing the new Barren Ridge Station on an existing Owens Rinaldi 230 kV line. That Barren Ridge Station will have a ten-mile transmission line 230 kV into the Tehachapi area to tie into the Pine Tree windfarm that we're currently building. And we have built both those facilities for additional projects that we're currently negotiating.

In our recent RFP a lot of interest for some high desert solar to come into that Barren Ridge Station. Our eventual goal would be to have 1100 megawatts of additional capacity being able to come into the Los Angeles area out of that region, which has a substantial amount of wind, as well as solar.

The bigger part of the project -- we've broken it into phases -- would be a new line going into our Castaic Power Plant. As you may know, Castaic Power Plant is a 1200 megawatt pump storage. So we will tie directly from the Tehachapi wind projects into the pump storage where we can have that ability for the intermittent resource to use the pumping capability and store that resource for when it's best utilized for the system.

So, very critical, long-term plan for us. The first phases, the Barren Ridge Station, currently under construction; about 85 percent complete. And that will tie into the Pine Tree. Eventual buildout should be complete by 2011, 2012 for all phases of the project.

And the third project is Greenpath North. As mentioned, there has been some recent

controversy over it, but everything seems to be proceeding. This would be a 1200 to 1600 megawatt project from a new substation, Devers 2, right next to the existing Devers, is where we're projecting it. It would come over and tie into -- it's an 85-mile transmission line, 500 kV -- tie into an area near Hesperia where we're proposing to build a new 500 kV station. And then upgrading existing 230 kV line back into Victorville from a 230 kV to a 500 kV.

This would, for the first time, tie IID's control area to L.A.'s. We are working jointly on the project from Devers down to a new substation in Indian Hills area. And then the upgrades in IID's territory. This is a joint project with IID, Burbank. Glendale, SCPPA and Citizens Energy.

That would conclude my comments.

PRESIDING MEMBER BYRON: You mentioned some recent problems with that line. Would you care to discuss what those are?

MR. HOWARD: Well, I think two real problems. One is, I think some environmental groups have raised some opposition and some issues about one of the routes. That is being reviewed.

We're currently looking into five routes. Some of the information they received was a little premature in nature.

There's a lot of work still that needs to be done on the environmental phases of the project, a lot of stakeholder community meetings. They received some partial information. And so the opposition and the barriers came up rather quickly.

So we have been working through that process with them. They have given us some good suggestions to look at some other alternatives that we are currently working on. BLM has given us some additional suggestions that we are working on, as well. So I think we're working through those.

There has been some controversy with IID and their board and some of their own projects and ability to proceed with their own projects, and the benefit to the ratepayers. We have been meeting with them. I think they have evaluated the Greenpath North project and determined that there is significant value to their ratepayers and the investment. And they have agreed to proceed with that project jointly with us.

To add to that, we have signed a development agreement with SCPPA, IID, LADWP to develop a first phase that will be a 200 megawatt geothermal power plant in the Salton Sea area. LA purchased about 5800 acres a year and a half ago. IID controls about 43,000 acres in that area. So jointly we're putting our properties together and our assets to develop some of the geothermal ourselves.

MR. HESTERS: Next we have Nam Nguyen from Southern California Edison.

MR. NGUYEN: Good morning, Commissioners and the Staff. My name is Nam Nguyen. I work at the interconnection planning at Edison.

First, I would like to thank you for the opportunity to present transmission projects to be included in the 2007 Strategic Investment Plan. Secondly, I, you know, would like to really support the change that the staff made regarding the time horizon for the transmission projects from five years to ten years.

Due to the nature of the transmission projects usually require a long lead time for permitting and project equipment procurement. I think that's a good idea to change it from five to

ten years.

As you may be aware, there were significant load growth that California experienced in the last few years due to the economic boom. And particularly in southern California, you know, we experienced a lot of load growth in certain areas.

And Edison will plan to invest over $4 billion on transmission upgrades so that we can meet the load demand, as well as maintaining reliability. And also integrating new resources in southern California.

As Mark presented earlier, the Palo Verde-Dever project number 2, still going, and as part of the project we include the western Devers upgrade. Due to the permitting issue that we replaced that upgrade with the Devers Valley 2 500 kV line.

However, because of the load growth, the eastern L.A. Basin area, the western Devers 220 kV upgrade still needed. And we plan to review those four 220 kV lines west of Devers with an upgrade date of 2010, '11 timeframe.

Also in the Palm Springs area there's also significant load growth there. We would need

to build a line from Devers to Mirage 220 kV line to meet that load demand in that area.

The Vincent-Mira Loma line, 500 kV line, it is a date of 2011. That project is still going, but now -- before it was a stand-alone project. Now it becomes part of the Tehachapi renewable project.

The Tehachapi transmission project for section 1-3 is still going. Go back to Vincent-Mira Loma, 500 kV line, that's the new 500 kV line from Vincent Substation to Mira Loma. So in the eastern L.A. Basin area. That's an 80-mile 500 kV line. That will help to relieve congestion south of Lugo path within the L.A. Basin area.

Also there are two other projects that we would like to be included in the strategic plan. The new Albert Hill Substation; it's a new 500 kV two 150 kV substation in the western Riverside County to serve load demand -- increased load in that area.

That new substation is going to be looped in by using existing Valley-Serrano 500 kV line. Another project that we have --

PRESIDING MEMBER BYRON: Can I ask you to just repeat the name of that first project

again, which you think should also be included in the plan?

MR. NGUYEN: Albert Hill 500 kV substation.

PRESIDING MEMBER BYRON: Albert Hill.

MR. NGUYEN: Yes. And that's going to be served by looping existing Valley Serrano 500 kV line. This project is going to be coordinated with the LEAPS projects once we have the final plan of service.

Another area that has experienced load growth is in the San Joaquin Valley, from Bakersfield to Tulare area. And we have plans to construct -- 220 kV lines from (inaudible) Substation. And we have an opening day for that 2012.

On the longer term projects that we'd like to include in the plan would be the second Valley-Serrano 500 kV line. That will help us to bring power, the resource from the eastern area into the Orange County area.

And, of course, the Tehachapi transmission project that has 11 segments. And the segment 4 - 11 is going to be later years, beyond 2017.

That would conclude my presentation on the transmission projects for Edison.

ASSOCIATE MEMBER GEESMAN: Just to make certain I heard you correctly, the Tehachapi segments 4 through 11, I think you said 2017, then?

MR. NGUYEN: Actually my correction, 2012 through '17.

MR. HESTERS: Any other questions? I would now like to open this up to anyone else who would like to discuss transmission projects that should be included, for comment on transmission projects for the Strategic Investment Plan.

MR. LAUCKHART: I just have a question --

MR. HESTERS: We need you to come to the microphone because it's being recorded.

PRESIDING MEMBER BYRON: Please introduce yourself, also.

MR. LAUCKHART: Sure. My name's Rich Lauckhart with Global Energy Decisions here in Sacramento, a consulting firm.

This question I would like to put to all members of the panel, but I'll ask it of Ben Morris because he has the biggest footprint in

California.

You know, when you're studying these kind of projects for reliability or economics or whatever purpose, you know, we need data out there to allow us to study our project in the context of everybody else's project.

WECC attempts to create that database. And we've heard a lot about projects here today. If we get a database on the power transmission grid for California from WECC in 2007, that's -- database, it's a pretty good database of what exists.

But what I'm curious about is when we talk about all these projects, if I get a database from WECC for example for the year 2015, are any of these projects put in there, does WECC have any rules on what goes into a 2015 database? How do you guys decide what you put in your data when they create the data for 2015.

So, Ben, I'll ask you that question first.

MR. MORRIS: Ben Morris, PG&E. To answer your question, it is really -- there ought to be more rules, I suppose, about what goes into the basecases, but generally speaking what we've

put into our basecase is into the database you refer to would be projects that have received some level of approval.

Generally speaking, it might be PG&E management approval, but also oftentimes Cal-ISO approval. So the kinds of projects, certainly I'll speak about the projects that I spoke about -- certainly these haven't risen quite to that level yet. Although we expect them to happen within the next, certainly before the end of the year, perhaps into next year that many of these could be approved.

At that point they would be entered into the basecase. And so next year's version of the basecase, as the 200 series, likely will contain many of these.

The only other -- from a database perspective, but I would also say that certainly from an investor-owned utility perspective, and being part of the Cal-ISO, and also under FERC order 890, there's a whole slew of things here that we're supposed to do, including having very open stakeholder processes. And that we do.

So, this information, much of it is discussed at stakeholder meetings. I'll speak for

PG&E here. We have several stakeholder meetings during the year, during which projects such as the ones that I spoke of, are presented and discussed.

So, certainly there are opportunities during the year to get it. But I do agree, the database records, the basecase records just cannot be kept up to date, I think, to the extent that you would like, Rich.

My message is there's other forums, other ways you can get this information.

MR. HOWARD: L.A. very similar; we are involved in a number of the planning groups and provide the data on these projects.

And it's one of the methods, as well, LADWP publishes every October our ten-year transmission assessment and our planning document. So that is available to anyone to review what our future plans, at least for the next ten years, we have outlined. It corresponds to our ten-year forecast and it's about as current as it gets, other than as the projects start moving forward they become a little more dynamic and those come out of the planning organizations.

MR. HESTERS: I think that's a pretty -- rather than going around the whole panel, that

seems to be a pretty thorough answer. Does that --

MR. LAUCKHART: That's good, thank you.

MR. HESTERS: Okay. Any other questions? We have one on the phone. Oh, sorry. Any questions from the phone? Anything on Webex? Okay, I think that's it.

Our next -- again, I'd like to reiterate that written comments are, we're asking for those by May 24th. If there were presentations or slides that you had that didn't get handed out, or actually we'd asked you to file those. We have some of those electronically, and we will make sure some of those are docketed. But we'd also appreciate some redundancy on that in case we don't have it.

Next up is Jim Bartridge to discuss corridors.

PRESIDING MEMBER BYRON: Gentlemen, thank you all very much.

ASSOCIATE MEMBER GEESMAN: Yes, thank you.

MR. HESTERS: And thank you. But please don't leave the panel because as soon as Jim's done we're going to do a panel on corridors.

PRESIDING MEMBER BYRON: Okay, good.

MR. BARTRIDGE: Good morning. I'm Jim Bartridge. I'd like to go over briefly what we have seen in the forms and instructions on corridors.

We talked about this, gave an overview of this in our April workshop. This is largely a follow-on. We've had a little more opportunity to get into the data, and we'll just go from there.

First of all, in the forms and instructions, I think that was adopted January 31st. We asked for it back March 31st. Gave folks two months to give us some information. We asked about corridors with opportunities to link with existing federal corridors, future corridors under 368 of the Energy Policy Act.

We asked about potential to impact sensitive lands that may not be appropriate locations for corridors. We asked how you considered in your corridor needs what you'd done with the Garamendi principles, if you'd considered them. Any work you've previously done with local agencies and areas that they've identified as sensitive that, you know, that you can share with us.

And we asked for any other known major issues that could potentially impact a future corridor designation.

So, here were the responses. Again, Mark went over most of this this morning. There were several, you'll see with the asterisk, that didn't specifically call out corridor issues in the response; and others that said not applicable to us.

So, for Southern California Edison they said the greatest opportunity lies in extending federally designated corridors to nonfederal lands in California. They felt that this would streamline the siting process. And that state designated corridors that don't line up with federal corridors are of little value.

Then they identified 11 existing corridors on federal land where the situation might apply. They also noted that southern California is surrounded by federally owned lands. And identified possible need for additional corridors across the federal lands will lead back to 368 process or 1221.

A couple things they also said: Wider corridor early in the process would help with

alternative selection later in permitting. They also recommended a transition width, a transition area going from the 3000-foot to 1500-foot corridors between fed and state. And that corridors could provide a means for environmental mitigation strategies. Do it earlier; less costly the sooner we do it.

PG&E, they provided us their 2006 electric grid plan. Identified a number of projects, over 90 of them, for the next ten years. They did not call out specific corridor needs that we were aware of.

For TANC, talked about the planned upgrades of COTP and the five projects you noted here. No specific corridor needs identified. But what we did see encouraging here was that they said, you know, we think you asked the right questions; and so we're going to use that as a guideline for reviewing future corridors. Thought that was worthwhile and very encouraging.

SDG&E. The Energy Commission should designate corridors along existing lines. Noted that their service area's constrained by sensitive lands. Designate corridors along 69 routes or greater that may eventually be upgraded to 230 kV.

And designation should not be tied to specific projects. But, again, in anticipation of future expansion of that path.

They noted corridors designation should also include expansion of existing substations. And should be coordinated again with federally designated corridors.

Imperial Irrigation District. Again, here they called out, they follow the Garamendi principles when starting to look at the need for new transmission lines. Currently in the process of identifying corridors for future lines, but no specific needs identified at this time.

LADWP noted rapid urban development in the area of projects could impact corridor designation. They noted Greenpath transmission projects. Tehachapi, the new corridor designation under 368 would be highly desirable.

So, again we'll see where -- I believe the 368 is going to be issued soon. I won't give you a date for that. We'll just see where that goes.

Western, no specific corridor needs identified. SMUD, ten-year assessment plan, no specific corridor needs identified. Turlock

Irrigation District, no corridor needs. Modesto Irrigation District, no corridor needs. Redding noted their system's only 115 or below. But again, no corridor needs identified.

Anaheim doesn't conduct any transmission planning; hasn't identified any corridor needs. Glendale Water and Power, LADWP operates, maintains their transmission. They didn't call out a need for corridors.

So, with what we have, we've come to three general conclusions, staff conclusions, that we think that, you know, for our recommendations in this first strategic plan, that corridors on nonfederal lands be needed to provide access to renewable resources, and help achieve RPS and greenhouse gas policy goals.

Corridors on nonfederal lands near load centers that could be threatened by continued development. They may not be available in the future. Or corridors needed to interconnect to existing federal corridors or potential corridors called out under 368.

So that's where we're going, or where I'm thinking for recommendations in the strategic plan. And so I just wanted to have an opportunity

to ask the panel here what critical corridors on nonfederal lands do you believe should be included in our strategic plan.

And with that, we'll just go back around the panel again.

Okay, and start with Dave Geier, San Diego Gas and Electric.

MR. GEIER: Thank you, again. I guess I'll start with the general comments and then get back to sort of answering the question.

I think throughout the last, you know, few years that really this whole corridor discussion has tied well with actually the transmission planning studies. And I think if you look at Tehachapi, you look at Sunrise, it really looks sort of grown out of that process where, you know, the transmission corridor planning is essential to actually getting those projects through licensing.

If there was, and I'm not sure if this is just more for consideration, if there was a corridor that's necessary in San Diego I think you can look at the two proposed routes for Sunrise. And if the 6000 megawatts, if even half of that were to develop in this timeframe, over 10 to 20

years, we'd probably need both those routes.

And as we study those routes, the process now, it may not be wise just to cast one of those away. And so I'm not sure we need to do some more thinking about that, but that will probably be our biggest need for San Diego is just to be able to connect to all those megawatts that could be in the Imperial Valley, and now in northern Mexico.

I think also I'd like to comment just on the corridor planning where I think it's a very valuable process, as I mentioned. I think it really has to be seen as a separate process from our previous panel. That we should not lose sight that it's more of a long-term need; and we really need to make sure that for short-term identified projects they go through the approval process and licensing process. So, really I see them as two distinct processes.

And one other comment was on today's agenda, at least, was sort of the existing right-of-ways and existing corridors that we have where we may have existing transmission lines today and the upgrade of those lines.

This is a very difficult issue, also.

And I think that it's worth considering, and maybe it's worth putting some policy out on. We've had numerous examples because just with the growth in southern California that we now have corridors, you know, one example where we have a 300-foot-wide corridor, actually part of the Sunrise project, as proposed. It's a blank corridor now. And it's been turned into a nice park and things of that nature.

Actually, once we looked at that and met with the homeowners, we decided it would be in everybody's best interest to propose that section of the line underground.

So there could be some policy that could come out that would describe how we use existing corridors. And, you know, maybe the point of having a preference on overhead construction where there's existing lines, and talk about the ability to upgrade those lines, I think a lot of the utilities are in the mode of, you know, looking at their existing right-of-ways to say, you know, if we're going to get from A to B use our existing corridor and do the upgrades.

And with just the natural growth that's happened, it can become very difficult. And

underground, I think, you know, is really not available at the 500 kV level now, but at 230 you're talking, you know, somewhere eight, ten times the cost. And that cost is all spread out to our existing customers.

So I think, you know, there's potentially some thought that should go into the existing corridors, also.

ASSOCIATE MEMBER GEESMAN: Yeah, Dave, I don't want to abandon that. I'd like to ask our staff to think more about how to utilize those existing corridors.

It seems to me in terms of looking to the responses to our filing requirements that at least in the near term this is a southern California problem. It's your service territory, Edison's to some extent and Los Angeles.

But this is a southern California challenge that we face. And probably pretty quickly it would be helpful for us to focus regionally in this discussion as opposed to generically.

Not coincidentally at all I think that southern California orientation matches up with the way the federal government is looking at this

problem and some of the difficulties that the federal government anticipates the state facing in meeting its transmission needs in southern California.

I want to come back to one of the things that came up in our April workshop, and ask your company and Edison to try to encourage some of your CEQA lawyers to give thought to the degree to which state government, as a whole, can segment some of these decisions.

Make the land use decisions, the corridor designations early in time. Accelerating them from years ahead of were we today make a decision in a CPCN. And attempt to narrow the scope of that CPCN decision to a question of timing and amount of investment.

Now, as I think most of you know, I'm of the belief that the federal government federalize these investment decisions more than ten years ago. But I know that there are those within state government that think that there's an important investment decision role that state government rules on.

So, I would narrow the scope of that CPCN to an investment timing and scale. And I

think with that division of labor we may be able to meet the deadlines that the federal government has imposed upon us for southern California transmission projects.

We might be able to actually satisfy a 12-month calendar on investment decision. If we don't, it strikes me that all of these decisions are going to be federalized. And I think that's the quite clear message coming from the DOE NIETC process. I personally tend to think that that's probably a good thing for California; force us to get our act together and make some of these land use and environmental decisions years in advance.

I think a companion piece to that would be allowing the utilities, once the state had designated a corridor, to invest in right-of-way and easements and carry that investment for up to 20 years in your ratebase.

I think that the policy of this Commission and the PUC have been pretty clear that we want to develop those 5000 or 6000 megawatts of renewable resources that you speak to, if the price for doing that is to develop a more forward-looking transmission planning process that can identify those corridors years in advance. I

think we ought to be willing to pay that price.

MR. GEIER: Yeah, I think one other issue that, as we talk about the CEQA, is that it appears we're heading to a fork in the road where you either follow the Garamendi principle with existing corridors, but for southern California that means you're into having impacts on, you know, lots of residents.

Or you go into sort of a, you know, a undisturbed federal or state land where there isn't the issues with the individual, you know, customers. But then, of course, there's all the environmental issues that go along with that.

That's something from a policy perspective I'm not sure if we decide nationally or in the state here. But there really is a clear tradeoff here, and sort of a fork in the road. And it's unclear at this time which way we'll go.

MR. BARTRIDGE: Ben Morris.

MR. MORRIS: Thank you, Commissioners, Staff, ladies and gentlemen. Earlier this morning I spoke about several projects that PG&E had on its radar screen to be built within the -- well, by the 2012, 2013 period were generally the timeframes that we were looking at.

As you could tell, and might well know, there's some very specific needs surrounding each of those projects. Mostly having to do with having to gain access to renewable resources. Help meet, or better meet the 20 percent probably above RPS targets.

What I want to talk about right now is some things that I think are a little bit less certain, but nonetheless probably still needed. One of the things that we have as a vision for the PG&E service territory is to ultimately get another 500 kV circuit that would run essentially, for lack of a better word, kind of the I-99, highway 99 corridor.

If you think of the intertie as interstate 5, we're speaking about now something moreover on the highway 99 side. So more on the east side of the valley.

And the projects I talked about are the makings of that -- earlier this morning, are the makings of that third circuit. So, in order to close that gap, I'd request that a corridor be considered from the Fresno area, from that new substation that we're talking about, that I spoke about earlier today, between Gregg and Helms.

So from that point there that new substation, again, up the east side and connect into stations like Billota which is, again, in the valley. Have some connections back into the Bay Area, but that would be the kinds of projects that I would be after or suggest.

By the way, I do have maps of this. And I note that Mark Hesters' request, and perhaps provide these back to the staff. I'll take care and do that. But essentially that's what we would be looking to do in terms of corridors.

So, in my view, corridor definition is very important. I think we're beginning, and have recognized, I think, for some time, that we need to identify corridors early on in the process.

And planning studies, transmission planning studies, I think, have to look out further in order to identify that. I think the 20-year time horizon frankly is about right. I think we need to have some vision and put some numbers on paper here to indicate what that plan might look like, and what might the drivers be to actually initiate construction on one of these corridors.

The concern here is that if we don't

identify the corridors, of course now, those corridors may not exist when you really need them. So, I think PG&E fully supports the idea of identifying these corridors for those reasons.

So, with that, I thank you.

ASSOCIATE MEMBER GEESMAN: Where is Billota?

MR. MORRIS: Billota, I'm sorry, I should -- Billota would be -- you know where Tesla is? I'll give you another place that you don't know.

ASSOCIATE MEMBER GEESMAN: Yeah.

MR. MORRIS: Okay, east of, it would be located approximately east of Tesla. So, it's out in that vicinity there.

And we have to have some cross-valley ties. Again, as I explained, the Bay Area is the load center for northern California. Of course, there's other load centers, Sacramento being one load center -- another load center.

But to get into the Bay Area, of course, we need to have corridors coming into the Bay Area. So I would suggest that up the east side, creating this third 500 kV line.

By the way, the lines that are being

discussed, the northern line that was discussed by TANC, by Jim Beck, fits into this. I mean the general concept here is what we're after. The idea here is that we need to get more transmission that would better unify northern and southern California. I think to achieve that we're going to have to get some 500 kV transmission that basically stretches the entire length of the PG&E service territory and ties better into TANC, SMUD and other municipalities to achieve that.

So, we're game for that. That's what we're trying to achieve.

PRESIDING MEMBER PFANNENSTIEL: Ben, would new transmission make a difference in how you use Helms, do you think? Would there be some way of using Helms for support for renewable energy projects, for example?

MR. MORRIS: Well, Commissioner, we -- definitely it would help. Right now Helms has some, lacks the capability to pump. The pumping window, if you will, is not as open as we would like to have it available.

So, building new transmission into Helms definitely, as Mark Hesters described this morning, definitely provides an opportunity for us

to pump more often, open that window, allow three-unit pumping at Helms, for example. That gives us quite a bit of leeway.

If your reference was to could it smooth out, if you will, the spikes that are seen with wind energy, yes, that could be -- that is something that would afford us an opportunity to do that.

But, of course, I come back to my same theme here, we need transmission into that area in order to achieve that. So that could help.

MR. BARTRIDGE: Okay, Jim Beck, Transmission Agency of Northern California.

MR. BECK: Thank you, Commissioners, Staff and ladies and gentlemen. TANC still has not identified any particular corridor that it believes needs to be included in the designation process in the strategic plan.

TANC does find the direction that staff is taking in trying to identify corridors to be consistent with its views that the best and most important uses first. We'll probably be making sure that you connect the dots, I think is the term we used in our comments that we submitted to you, between any federal designations so that the

corridor becomes useful within the state.

And then finally we'd note that this is a tool that likely will become much more important as time goes by, as we try to make the decisions that we have to make with respect to the investments that are called for in transmission facilities.

So, we commend your process; and those are my comments.

MR. BARTRIDGE: Ed.

MR. CHANG: I'm Ed Chang with Flynn Resource Consultants, representing the BAMx group again.

In terms of corridors, as I mentioned in my previous comments, the project that the BAMx are sponsoring in the long-term Greater Bay Area study effort, and also in the TANC transmission program, is open to looking at different approaches to increase the import capacity into the Greater Bay Area.

That goal is, again, to reduce congestion costs, reduce local capacity need, and, of course, accessing renewables.

Now, specific project that they've been looking at would utilize an existing corridor

following the Garamendi principles, but I don't know if you recall in my March 5th presentation I had a very complex one-line diagram, and also had a simpler circle diagram. And it essentially showed by three arrows kind of the major import, the three major import corridors, if you will, into the Greater Bay Area, defined by that cut plane.

So look at your March 5th record; you'll see some existing corridors.

But my sense is that, maybe Ben can add to this, if PG&E's considering a 500 kV substation in the Greater Bay Area, my sense is that you'd probably need another corridor.

But we're looking at the 230 option. So, in terms of just a little bit more background, the BAMx group, through the Department of Energy National Interest Electric Transmission Corridor Process, did request early in the process early last year, a designation of the Greater Bay Area.

During the comments on the congestion study we did say hold off for that designation until we complete the longer term Greater Bay Area study.

So we expect either utilizing existing

corridors to the extent we can, or perhaps new corridors may be needed. Thank you.

MR. HOWARD: Randy Howard, LADWP. I don't know that I fully agree with that question. And one of the things that I would offer up regarding the question on nonfederal lands, I think the state has a little bit more significant role, and a role that the IEPR can play.

It comes back to under approximately 20 years ago the California Desert Conservation Area corridors, during that timeframe when they designated the conservation area for the desert, many parties negotiated utility corridors.

Now, going almost 20 years later, looking to utilize potentially some of the corridors, is a recognition that piecemeal over the years as say Joshua Tree expanded, it expanded right through the middle of the corridor. So it just took the corridor out. And it was just an individual legislative move for the expansion of Joshua Tree without considering the global aspects.

I think this Commission and the state can have a role to play, as Barbara Boxer's bringing forward her wilderness bill, that's one

of the things we recognize. That, again, it takes away some of the existing designated corridors through federal lands.

So I think there would be a lot of usefulness in the state more actively participating in that process to insure that there are at least the designated federal corridors that were previously identified, are retained. So, I'd like to see that as part of the IEPR going forward.

Another opportunity that I think exists that should be included in the strategic plan would be there have been a number of bond issuances for the expansion of freeways, primarily, and infrastructure associated with freeways.

I'd like to see a little more coordination as Caltrans goes out and does condemnation for the expansion of the freeways, we really should look at those opportunities for the transmission right-of-ways in those condemnation processes. And some more joint work. L.A., in particular, obviously looking up that 10 corridor and the I-15 corridor as we're looking at alternatives for the Greenpath.

Within the L.A. Basin, itself, as we continue to work through some of the issues on the 101 corridor, the 405 corridor, we will possibly look for those opportunities, as Caltrans has to do some level of condemnation for the expansion of those freeways, for opportunities for some corridor expansions.

And lastly, I think the opportunity is here. L.A.'s looking at it. And it's really, because we continue to see the growth around our existing transmission lines and our existing easements, and rights-of-way, and that's where we're first touching on for our expansion plans or upgrades, is we're looking at opportunities now where we might lock up additional easements.

So, going ahead, negotiating new easements, wider easements for future growth long term on those corridors. And I think just having the existing is one thing. But some of them are quite narrow, and with the expansion coming around them, it might be the right time to support renegotiating and seeking more easements on the existing corridors.

So, with that, that will conclude my comments.

PRESIDING MEMBER BYRON: Mr. Howard, you may, or maybe a member of the staff may know, is your idea of coordinating transmission corridors with potential highway condemnation issues with the Department of Transportation, is that a new idea? Or have there been examples of that in the past?

MR. HOWARD: I'm not aware of any examples. We've just seen, as they're looking for the expansion of the freeways and we're dealing with relocation issues that might occur there, that maybe there's an opportunity in those condemnation processes and the expansions to tie.

What you've come down to is a big fight, though, when you get to the CEQA part. Because nobody wants to tie those two issues together. It's hard enough to get your own issue through. But tying the two together becomes very very difficult.

But for the better good of all, it might be the way we're going to have to approach some of these expansions.

PRESIDING MEMBER BYRON: Can I ask if the staff could comment on that? Do you know, has there been any examples of that?

MR. BARTRIDGE: Actually Chris Tooker and myself, we went back, probably a year and a half back. We went over and met with Caltrans and talked to them about this issue. But it hasn't gone very far since then.

MR. GEIER: As Commissioner Geesman alluded to, some of the corridor issues are unique to southern California. But I would agree with Randy, that we've had considerable discussion with Caltrans. And it always seems to come up a little bit short.

And, you know, I think one thing we've been encouraging is all the state agencies and the federal agencies sort of talk and work together on these issues. And actually we had a couple alternatives that were parallel to highway 8 for Sunrise.

And I would characterize our work with Caltrans as better than usual on these projects. But it still sort of tends to fall short a lot of time.

I think, as Randy alluded to, it does open a whole other can of worms when you start working through these issues. But as we're looking forward, we're looking at infrastructure

issues for the state, it's another great area for coordination.

MR. GEIER: And I will add, I mean, currently within the City of Los Angeles, obviously being a City department is a little easier, but our Department of Transportation cannot tear up a street without first coordinating it with all the other utilities to insure that we all do our work together at that point.

And therefore we come up with a joint project that benefits the entire community. And maybe it would be better served if we can figure out a method to do that with Caltrans as they're proposing these projects.

PRESIDING MEMBER BYRON: Also I'm not familiar with the Boxer wilderness bill that you refer to. But I was wondering again, maybe the staff was aware of this bill at all, or had considered any of the implications that Mr. Howard indicated where it could potentially close off existing corridors.

MR. BARTRIDGE: We've actually mapped that data in our large transmission corridor database, yeah. We're working with that.

PRESIDING MEMBER BYRON: Thank you.

MR. BARTRIDGE: And Nam from SCE.

MR. NGUYEN: Commissioners, this is Nam Nguyen again. I think Jim very much summarized well Edison position, you know, comments on the corridors.

But I would like to reiterate the need to extend the corridors in southern California, especially in the L.A. Basin area. It's very much landlocked area. The load continue to increase over the years and expected to increase in the future.

We obviously need additional transmission capacity to bring power from outside into the L.A. Basin with these increased load.

We did submit the 11 corridors to the DOE I think more than a year ago. And we'd like to see if the Commission can, you know, once the DOE designate these 11 corridors that we recommended, we would encourage that the Commission can extend that into beyond the federal-owned land into other land to make complete, useful corridors.

On another side, mentioned earlier, is the San Joaquin Valley where along the 99 highway there should be another corridor that should be

designated to serve the load in the area.

Earlier I mentioned that we have a project, 20 kV lines, double circuit, is built from McKendon (phonetic) to Tulare to serve that load in the future.

On the side, another issue that I would like to bring up to the attention of the Commission, is the joint land use study currently conducted by the Governor's Office of Planning and Research.

This is a (inaudible) between the Governor's Office and other stakeholders to develop land use compatible between local communities and the military operations.

However, there's little consideration given to the public utilities by Edison in the planning effort for future transmission corridors. That may adversely impact our future plan to build transmission line in the Mojave Desert.

Therefore, I encourage the Commission get involved to facilitate transmission corridor planning in the area. I think there two areas, Mojave Desert and another one in, I believe in Kern County area.

MR. BARTRIDGE: Ben, did you have a

clarification remark?

MR. MORRIS: Yeah; Ben Morris. I just wanted to comment on something that Ed Chang said. He mentioned, and perhaps just some clarification that I need, about what is going on.

Earlier this morning we did talk about, I thought, some very specific plans that we'd like to have incorporated in the CEC report. And I view those as beyond corridors, in the sense that we have identified specific needs for these projects. We don't know exactly in some cases which alternative may be implemented, but we believe, based on identified need, that something will be constructed.

On the other side of the coin you've got corridors, which are further out in time. I think that's the way that it's been explained. Perhaps a little less certainty right now about the timing for when the actual transmission construction would take place.

So the clarification Ed mentioned, and perhaps he's right, but I wanted to just bring this out, that he mentioned we ought to be requesting a corridor to tie the Sunol 500 230 kV station back into the main 500 kV lines that run

south of Tesla.

And I guess our need for this Bay Area 500 kV station, I think, is soon; much sooner than I think than the corridor designations are being talked about.

So, I think I would just comment that the reason that we've not identified that as a corridor requirement is I believe the need for the Bay Area 500 kV station at Sunol is much sooner than what is being envisioned with the corridor designations.

MR. BARTRIDGE: Any questions in the room? Any on the phone?

Well, with that, if you'd like to adjourn for an early lunch.

PRESIDING MEMBER PFANNENSTIEL: Sounds great. We'll be back at 1:00.

(Whereupon, at 11:45 a.m., the Joint Committee Workshop was adjourned, to reconvene at 1:00 p.m., this same day.)

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AFTERNOON SESSION

1:06 p.m.

PRESIDING MEMBER PFANNENSTIEL: I think we should get started; we've got a full afternoon and it's a little after 1:00. So if people would take their seats.

Jim, are you MC-ing this afternoon, or who's taking it?

MR. McCLUSKEY: I will in a very general sense. Ready? Good afternoon, Commissioners. I'm Jim McCluskey. Part of the work is devoted towards interstate transmission projects and the issues associated actually for specific interstate projects, the issues and potential barriers affecting -- that affect them; and the potential benefits they could provide California and the rest of the western interconnection.

The agenda for the afternoon is pretty self-explanatory. We're going to begin with an overview presentation by Jim Sims; and that will be followed by a presentation by Joe Eto on cost allocation issues and transmission planning issues, to a certain extent.

So, I think it's -- Jim's PowerPoints are up, so we might as well just begin with him.

MR. SIMS: Good afternoon, Commissioners, ladies and gentlemen. Thank you for having me today. I'm Jim Sims; I work in Denver, Colorado. I have worked for the last couple of years in helping to build bipartisan support across the west for more transmission.

I've been involved with a number of the various governors' offices in the west and several projects, including the Frontier Line. But I wanted to talk a little more generically today about where the political landscape -- what the political landscape now looks like in terms of interstate regional transmission, mostly in the western United States.

What we'll cover today quickly, and slow me down if I go too fast; since I have 20 minutes I'm going to try to rip through this pretty quickly. What more transmission means, again, regionally. What less transmission means. The general transmission landscape, both in terms of politics of transmission and in terms of some of the investment trends that we're seeing.

Barriers to greater investment in transmission. Strategies for overcoming those barriers. What I call the coming greenwires

revolution. And then finally climate change as a transmission driver.

What does more transmission mean? Well, most of us know the answer to this, but I think it's good to keep reciting that transmission is a good thing. And, in fact, from California's perspective and many states in the west, believe it is required in terms of having more investment.

Number one, reliability, keeping the lights on. A lot of people take, in the public who don't do what you do day in and day out, or what most of the folks in this audience do. American people generally think when they flip their lights on, the lights are going to go on every time. Sometimes that doesn't happen. And a lot of work goes behind making sure that those lights go on. Transmission is a key component of insuring we have reliability in our system.

Diversity of energy supply, in and of itself, I think, is a very important public policy goal. That leads to the next point, it provides us with the ability to rely more on our own American energy resources, less foreign imports. That leads to enhanced national security; insurance against price spikes; access to more

remote renewables, since most renewable energy resources are located far from load.

Access to climate friendly power generation, which we'll talk about in a minute. Driver for breakthrough technologies. Without greater investment in transmission, new lines going up, we don't have as much investment in the power generation technologies that we need these days.

And then finally distributed generation incentives; to the extent that we have a more robust grid, it gives people at the consumer end a better chance to have their own distributed generation to sell back to the grid.

What does less transmission mean? Service disruptions, obviously, blackouts, brownouts, economic disruptions. The costs, widely defined of large scale, even small scale brownouts and blackouts are huge, as I know you know.

Less access to renewables with less transmission; higher delivered energy costs; higher consumer product costs; higher manufacturing costs. Exercise of market power by participants. And generally speaking, a more

short-term planning horizon, more of a crisis mode, which we often find ourselves in.

The landscape today for interstate transmission can be described in a couple ways. This is one way to do it, for example. During much of the past 20 years transmission capacity was added, as you know, at a much slower rate than consumer demand was growing. Between 1982 and '92, for example, capacity per megawatt hour of peak demand declined at an average rate of .9 percent per year. during the following decade capacity declined even more rapidly at 2.1 percent per year.

This shows the results of a study recently done by the Edison Electric Institute which focused just on IOUs. But this shows that between 1975 and 1998 a relatively sharp and steady decline in investment in transmission infrastructures.

The NERC report, which I'm sure you've seen a copy of, showed some very very disturbing -- came to some very disturbing conclusions with regard to generation capacity in general, and transmission buildout in particular.

For example, they concluded that

electric capacity margins will decline over 2006 to 2015 in most regions here in the west. We're looking at probably starting to exceed those in the next ten years, or at the end of this next ten-year period.

Utilities see demand increasing over the next ten years by the numbers that you see. They project committed resources to increase by only 6 percent; 9 percent in Canada.

The available capacity margins are projected to drop below minimum regional targets, I want to underscore that, in ERCOT, MRO, New England, RFC, et cetera; and in other portions of the northeastern and southwest, and the western U.S. In the WECC region we see these capacity margins dropping below the minimum regional targets, probably toward the end of this next ten-year period.

This is a graph from the NERC study, which shows the top line is the high demand projection. You'll see it bisecting the regional capacity projection at about 2013. Under the base demand projection it will meet up with about just past 2015, and we have a low demand projection. It'll take a little while longer.

Basically it's telling us that we have trouble on the horizon unless we are able to build the generation that we need and the transmission necessary to wheel that power.

Fifty-thousand megawatts of uncommitted resources exist today that, one, do not have firm contracts or legal or regulatory requirement to serve load. Two, lack the firm transmission service or a transmission study to determine availability for delivery. And, three, are designated as energy-only resources, or, four, are in moth-balled status.

And over the next ten years those uncommitted resources will more than double. And those resources represent, obviously, a viable source of the incremental resources that we need to meet those minimum regional target levels.

And as NERC pointed out in the study, the lack of adequate transmission emergency transfer capability is going to limit our ability to move power where we have an excess to power where we have a need.

NERC's bottomline in this very seminal study, electric capacity margins will continue to decline; and action is needed to avoid shortages.

Not just high prices, but actual shortages, in NERC's view.

The landscape today is also colored by what the federal government is doing, mostly in reaction to the 2003 blackout, and pressure by this past Congress to move forward, encourage more transmission buildout. You'll see that -- and I know you've gone over this map, this is the NIETC corridors, proposed NIETC corridors. This is the critical congestion area study. A lot of this is obviously in southern California.

Now, having said all of that, the picture over the last 20 years has been, I would say, alarming with regard to a lack of investment in regional transmission buildout.

However, there is also good news. The good news that in the last several years, as this graph, which you saw earlier, by Edison Electric shows, the last number of years investment has turned around. A lot of investor-owned utilities in addition to those utilities in the public power markets are starting to invest significant new dollars in both short-term and eventually long-term lines. It's very good news.

This shows all of the various proposed

transmission projects around the WECC region. Some of these are, frankly, more real than others. You'll see there are, generally they're defined as sort of megaprojects, or large projects. There are several of those. The TransWest Express line; the Northern Lights proposed project; the Northern California/Canada line; the Frontier line.

And then some subregional, near-term projects that are in the permitting phase, Palo Verde-Devers, Sunrise Power Link and the Montana/ Alberta intertie.

There are a number of others, and there are a couple that aren't on this map that are now being discussed by groups of companies. The point here is that there is a lot of activity. Five, six, seven, eights ago very very little activity. In fact, we were in the throes of sort of, as states, pushing back on FERC. Now you see a great deal of interstate transmission projects, and a political -- a much greater increase in the amount of political multistate cooperation that we're seeing by elected officials, from governors on down, on these various projects.

I think we are in the middle of a transmission renaissance here in the west. There

is a political drive from all states in the west, particularly California, for more renewables, generally speaking, in the west.

Renewables are located, the best renewables are often located far from load, requiring transmission. There is a rise of more merchant transmission. Investor-owned utilities and co-ops are looking more regionally in terms of their resource acquisition.

There's a new political reality, I would argue, in the west. And frankly, it was started by this state and several others with the vision of a frontier line, if that's what you want to call it, where five or six years ago governors and others were just spending most of their time pushing back on Washington. Stay out of our state affairs. Let us, in our own states, determine where and when we build transmission.

Now governors and state legislatures and many others are starting to work, in my view, much more regionally. And I think that's a good thing.

The federal government's reaction to the 2003 blackout, frankly, has sparked a great deal of activity, led by the Department of Energy and the Congress. There are increasing national

security concerns related to our rise of imports of foreign energy. And, of course, climate change as a policy driver, I would argue, is also increasing the political process' view of transmission and increasing, I think, the political reality that we need more transmission to access remote renewables.

The grid, I think, is going to get a lot smarter, as well. Smart grid technologies are getting a new focus. If you look at achieving only a 5 percent efficiency gain in our current grid, that would amount to 42 large coal plants that would not have to be built.

Smart meters, real-time pricing, grid-friendly appliances that sense when there is something of an emergency and will back off individual appliances. My refrigerator would back off of some of its power needs in that instance.

Plug-in electric vehicles have the capacity eventually to help us manage load and demand.

What are some of the barriers to more transmission. There are many of them. That's one of the reasons why, in my view, we haven't had a lot of transmission built in the last 20 years. Increasing concerns over climate change, and the

resultant concerns that are expressed about fossil energy baseload generation.

There are always siting issues and public lands, sensitive lands. There is the NIMBY phenomenon. There is the conflicting patchwork of regulatory environments that we have, really around the country. And in particular, without a regionwide RTO. We have that here in the west.

Financing cost allocation issues. One of the biggest impediments that I see to more investment in transmission, however, there's a lack of education in the public on just what transmission is, and how central transmission is to our quality of life and our standard of living here in the country.

Overcoming these barriers. I'm not going to get too much into this because many people have different views on this. More integrated regional planning in the west is a must. A longer term planning horizon is a must. State and federal investment incentives. There ar many ways to go there. National interest corridors, various levels of corridors that I know you've talked about earlier today.

Federal backstop siting authority. I

was not going to list that on this slide, quite frankly. It's out there. And there are those who will say that in certain circumstances that may be necessary to move projects forward.

DOE lead agency status. And as you can see, public education, public education, public education. I'm a big believer that if we are able to help the public understand how intrinsically important transmission is, we might not have as much of the NIMBYism and the other barriers that we're seeing to transmission.

What I call the greenwires revolution. I think we're in the midst of this. And simply this, that moving our generation to a more climate-friendly and a greener, more environmentally sensitive base is going to require transmission.

Until the day when we can find a way of generating green energy right at load, we're going to have to build large lines to build the large wind, the megaprojects that everyone wants to have. For a megawind project or a megasolar project, geothermal, you've got to have megalines.

So to the extent that we can help the public understand that green energy, the

transmission is a path to green energy, which, in fact, it is, that will be very important.

In fact, I think you can talk about transmission moving forward in a way to getting us to a cleaner and more climate friendly environment, unleashing renewables like geothermal and wind and solar and biomass and hydropower. Eventually near-zero or zero emission coal technologies. Creates jobs for America. It provides consumers and families with relatively affordable energy. It helps maintain the lifestyle that we in America have become accustomed to. And it's moving us toward a future that is much more environmentally sound and sensitive.

The greenwires campaign which we are engaged in is again to help the public see these greenenergy highways. We're doing a number of educational outreach things to help the public understand that those nasty transmission lines that you see are actually a good thing.

Climate change is a key driver. I just want to end with this quickly. Mega renewable projects are going to require megatransmission lines. The drive toward nearer zero emission coal

technologies, when we eventually get there, also will require transmission lines.

And then finally I would just note, as all of you know this intrinsically, and that is that reliability, keeping the lights on and trying to deliver to consumers not just reliable energy, but affordable energy, are concerns that will not go away. And without increasing stead investment in transmission I will argue strenuously that we will have difficulty maintaining reliability and low-priced energy for consumers.

And that's my presentation. Be happy to take questions or go to the next round.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Questions from the dais.

PRESIDING MEMBER BYRON: Mr. Sims, good to see you.

MR. SIMS: Thank you, sir.

PRESIDING MEMBER BYRON: Thank you for coming. As I recall we met last year.

MR. SIMS: We did.

PRESIDING MEMBER BYRON: I gave a presentation from a customer's perspective on the need for additional transmission. And a number of the points in your early slides look similar to

some of the same points that I was making.

Have you factored in some of your conclusions, what the implications of our recent legislation, SB-1368 and AB-32, might have on the need for additional transmission in the west?

MR. SIMS: How much time do we have?

(Laughter.)

MR. SIMS: That's a -- I've given a lot of thought to that and the short answer, Commissioners, is I don't know the answer because I believe, it's my perception, and I don't live here in the State of California, but that California policymakers such as yourself are still wrestling with what that means.

The short answer to your question is that I think that California moving in the direction in which it's going, more renewables, more climate-friendly technologies is going to require more import of out-of-state power. That's my own personal view.

Can California do this all with instate renewables? Maybe. I think the perception is that California may have difficulty in achieving its 20 percent RPS by 2010, maybe it won't. Regardless, I think the insurance that it provides

California in terms of being able to tap into out-of-state renewables, if you need to, is very very important.

I would also say that to the extent that California is going to continue to need baseload generation, which I trust, as your economy grows you will. Right now you're looking at sort of one option. And as a formal geothermal energy lobbyist I don't like to say that the renewables are not baseload, geothermal is baseload. And there isn't just enough of it.

But in terms of additional baseload power generation you're just going to gas. Not that there's anything wrong with that. But I would fear that if you just go to gas, we're looking at potentially, in my view, supply constraints. Quite frankly, to the extent that we're pushing the process toward only natural gas combined cycle plants.

And the political process on the other hand is trying to constrict supply. That is the outcome of a great deal of the opposition that we're seeing around the west to more natural gas development, exploration and production. I think you're looking at a dangerous potential collision.

So, transmission, greater transmission, interstate transmission in general, I will argue, will drive and accelerate investment in other baseload power technologies that can meet these two standards. Eventually that will mean, I hope, coal-fired power, in addition to large baseload solar, in addition to natural gas combined cycle, in addition to geothermal, in addition to all of them.

Without transmission California will become more of an island, in my view. And there's only so much renewables we're going to be able to get here in the state. I mean, we need more transmission within the State of California.

And if California starts to go further with its RPS, which I know is potentially an option, you folks tell me, I don't know if you can get that all from instate. I know it would be better if you could, but I'm not sure you'll be able to.

PRESIDING MEMBER BYRON: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

MR. SIMS: Thank you very much.

MR. McCLUSKEY: Joe Eto is the next

presenter, and he'll discuss his interim report on cost allocation and strategic benefits.

MR. ETO: Good afternoon, Commissioners, Advisors, ladies and gentlemen. Thank you for the opportunity to talk about our research project. Let me introduce other members of my project team. From the electric power group, Vikram Budhraja, Fred Mobasheri, Jim Dyer, John Ballance, and Jaime Medina. From Alison Silverstein Consulting, Alison Silverstein.

I'd like to also very much thank the PIER transmission research program which is sponsoring this research. We do a lot of work for the PIER transmission research program and some of the technologies that are involved at the ISO. And I think it's very appropriate to be able to balance some of those more technical things with the types of analysis about new benefit research methodologies. And put that into the public domain.

What I'm going to be doing is giving you an interim report about a status of a project that we've been working on for a little bit now. We're about to come out with our draft report very shortly, so this is going to be kind of a preview

of that activity.

I'll start by telling you more about what this project is and is not; and then highlight some key emerging themes. I know that the time is short, so I'm going to spend a certain amount of time on those emerging themes, and then the rest of the slides will try to illustrate some of those points more fully.

I guess at bottom this research project is all about the problems that transmission plays a very important part of our modern infrastructure. It's also a recognition that building transmission now is much more complicated than ever. And it's complicated because there are both public and private decisions that are involved; and because as a result of the changes in our regulatory landscape many more parties are involved. And consensus is required among all in our move forward.

This project is really focused on the proposition that if we are able to consider the full range of benefits and costs associated with these projects, we will improve that decisionmaking process.

So, it's toward that end that we are

focusing on making sure that we look at the full range of benefits and costs associated with projects, looking very closely at then who receives them and who incurs those costs.

We were asked specifically to look at how new transmission technology might affect these impacts and the affected parties. And in particular, look at the question of how might these impacts be quantified. And then look retrospectively at how our emerging processes trying to deal with these issues.

One of the things that we were really asked to bring forward was are there some new approaches, some new things. I think we do have some things to share that I hope will be very helpful to you all.

Let me tell you again what the study is and is not. We were charged with developing recommendations and a strawperson guideline on benefit quantification, cost allocation and cost recovery to inform current planning processes, specific regulatory proceedings, and future stakeholder processes for policy development.

One area that we're specifically focusing on is identifying some areas in need of

further research. And I'll talk about two very very promising areas that we've uncovered in our work to date.

I also want to be very clear that we are not attempting to seek a consensus among stakeholders about what are the benefits, what is the best cost allocation method, and what is the best cost recovery method. So, to that end, we are not making recommendations with regard to any specific project. I just want to make that disclaimer very clear upfront. That this is bringing more signs and more information to these decision processes, it's not a substitute for those processes.

So this, in a nutshell, is where we are at. I think the first few bullets speak to this issue of property rights. And the basic story about restructuring is it's made the question of property rights associated with the construction of new transmission much more difficult. This is the fundamental issue. Can you get what you're investing your money on. Can you get a return on that, and the property rights associated with those investments, and the challenges that flow from that.

We have looked broadly across the U.S. at other restructuring activities. There are important insights about the need for stakeholder consensus and some means for achieving that consensus. But fundamentally it's about insuring that there is a fair assessment of the benefits and costs and a fair process by which those benefits and costs can be fairly aligned.

We looked, as result of advice from advisory committee, at other industries. In particular, telecommunications and natural gas are often pointed to as models where some of these things have been worked out. And I think there are very very limited lessons.

Again, it stems from the very tricky issue of ac power networks and the difficulty of securing property rights in those types of investments in that type of a setting.

And as key distinct, there are some lessons from these other industries, but they're very limited because of this fundamental nature about electricity.

I'm a big supporter of technology; and I think technology has lots of benefits. And those things will definitely flow into the project

approval process. But I think they have very limited impacts on the cost allocation and cost recovery issues. And, again, I'll speak to that in a very -- with a very clear example when I get to that point.

But again, it's property rights, property rights, property rights.

Looking at the more positive side of some of the analysis that we're doing, we look at the methods that are being used in some of these approval processes. And we find that many of these processes are omitting important benefits that we think should be accounted in a fair assessment of the cost and benefits of some of these projects.

Some of these benefits can be readily accommodated into the existing processes. And we'll talk about some examples of how that's being done. And I'll encourage more of that type of thing.

But others, and we're going to point specifically to the avoidance of extreme bad things happening, which is something that really speaks to societal preference, a societal risk aversion to bad catastrophic things happening.

It's something that we think is very important and it's not captured in your traditional expected value type of calculation.

We think new methods would be required to try to approach this. We have some thoughts about what those might look like. I'll share some of our initial thoughts with you about what those things might look like.

Bottomline here is that in looking at these cost allocation/cost recovery issues, it's very clear that the hard decisions that need to get made are made much easier if the pie is made much bigger and there's more to share all around. And that's really, I would say, the focus and the thrust of the kind of research that we're trying to do in this project.

So, the rules have changed. Fundamentally, vertically integrated firms that used to plan, own and operate transmission are now being -- have been vertically integrated into an open-access world. And this comment about open-access is extremely important to this property rights discussion.

From a planning perspective it's transition from utilities to the ISO with

stakeholder participation including the utilities.

Regionally it used to be the footprint utilities only. That's now evolved to WECC utilities with regional stakeholder participation. In that regard I'd like to commend things like the TEPPC process that have emerged within the west to provide a forum where some of those discussions can take place in a very appropriate open manner.

But again it speaks to this question of much more complexity, many more stakeholders involved, many more people that need to be -- whose needs need to be addressed in the consensus building process.

And a particular issue that I really want to focus on is this issue of usage rights. In an open access world the rules for how you get to claim the benefits from the project that you have invested in have changed fundamentally. And this is really going to be a theme I'm going to come back to over and over again throughout this process.

This backdrop really set in stage our work to try to look both at what other parts of the country have done, as well as what other industries have done basically, this basic change

in the structure of our industry here.

So, looking across the country, you know, we find that it's important to recognize that transmission planning and approval, cost allocation are essentially consensus building activities. That's at root what they are.

So there's key features to those. One, across the country they don't spring up overnight. Takes years to make some of these processes work. And you see that years of investment paying off in many parts of the country where regional planning processes are growing up.

Key to the success of those processes is the credibility of that process. In the independent, the unbiased that is perceived by all stakeholders of the types of analysis that are being used, the openness of the data, the public participation. I want to speak especially to the FERC 890 of strawman guidelines that promote this type of thing. I think this is essential for reaching consensus about these very difficult issues, about what are the benefits, how big are they, who are they accruing to, who are bearing these costs.

To the extent that basic information can

be put into the public process, it's going to improve the decisionmaking that comes out of it.

I think it's for that reason, and again I'm saying, the construction is going to fall to certainty of people putting their money in, and getting their money back. That's very obvious.

And so to this regard it's the specifics of the (inaudible) are not that important. So, you know, those 80/20 sharing in other parts of the U.S., there's specific methods by which local and network kinds of decisionmaking are made for cost allocations.

The specifics and mechanics are less important, the formulas are less important than the agreements that are reached among the parties about the fairness of the process by which those decisions are arrived at.

I will even make the argument at some point it may be appropriate to have an arbitrary formula, as long as everybody can agree to those principles and to that end result.

So, again, here's a situation where, you know, I would never say the means justify the end, but here, in many cases, the ends are more important than the means, and the specific

formulas that you use, than that there is regional agreement about the need for these projects in a fair way of sharing the costs and benefits among all parties.

So, we see across the country is that this is a, you know, a building process. You know, the very early ISO transmission plans were sort of stapled together local reliability upgrades from the individual participating owners. Those build up to backbone projects, and ultimately to inregion, you're just now seeing inregion projects that are predicated primarily or principally on economic benefits in addition to the reliability benefits.

That takes time. That's a process of stakeholders getting used to one another, getting used to talking to one another, getting agreement about the data and the methods that are used to calculate the benefits and the costs associated with those projects.

I think the lesson, though, that we learn here in California and the west is actually rather limited in that regard. Because major intrajurisidictional backbone transmission projects are just now being tackled. There really

isn't a good precedent for these projects.

There are good precedents for big projects within the footprints of the ISOs back east. But there are not good precedents yet for large projects crossing multiple jurisdictions. And that's fundamentally our issue here out west.

So we can draw limited insight from that.

At the same time we can also draw some comfort from the fact that California does have 18,000 megawatts of interconnections with neighboring states. We have been building interregional transmission for a long time now. We have a very good record of relationships through the WECC planning processes and other discussions that have gone on to build upon. And we should take credit for that, as we go forward.

And particularly because these projects are going to grow in importance as we go forward. So it's important not just the studies, but this is going to be a central part of the transmission planning process as the years unfold.

Property rights issues really manifest themselves in the ability to secure and fairly pay for the benefits associated with transmission projects. And so the lessons that we learn from

these other industries flow directly from this.

In gas, the flows are relatively controllable. You don't have the problem of -- law or -- cost law sending the gas any which way the pipelines might be configured.

Telecommunications, again very different situation. Very high technological innovation. Technological obsolescence is causing the turnover more than stranded telecommunication assets.

And the issues of cost allocation that have been addressed in telecommunication really are really between local and network long distance service. They have less been among the different customer classes or across a jurisdiction served by telecommunications. Again, very limited lessons.

To the extent that we see lessons learned, there's some very basic principles. You know, if the benefits are diffuse over many parties, very hard to get precise quantification of who's getting what. Very hard to sort of slice it very thinly. Therefore very difficult to have a discussion about what is the fair way, the most fair way, or the most precise way to split those benefits up.

More players involved in decision. Again, longer and harder time to make decisions; to have commonly accepted approaches. Again, this is why some amount of socialization or really effectively arbitrary formulae may be the most appropriate way of going forward. Recognizing everybody could be equally unhappy as opposed to trying to make everybody equally happy.

Again, and this goes back to the basis of our work, the more that you have the more you have to share. I think that's a very fundamental principle. So getting more on the table by making sure that you're clear about all the benefits associated with transmission, very important for moving some of these cost allocations issues forward.

This was somewhat of a surprise to us looking at advanced transmission technologies. You know, there's lots of technologies out there. Some of them increase line capacity. That's going to increase the overall benefits associated with transmission of a particular type. There's lots of technologies do that.

Some technologies also improve power flow control, your ability to route the power in

particular ways. One of the interesting things, though, is you can't really change Ohms law. So if you control the power in one place you're basically pushing it around into other places and increasing losses elsewhere.

And in very and particular -- let me come back to that because that's my final point -- there's a couple of areas where we think these things have specific roles to play, particularly on the benefits side.

Certainly in dense urban areas where building new towers is very difficult. Some of these advanced conductors to get more through-flow and -- very promising.

The flow control technologies have lots of benefits in terms of the control-ability flow, but really they're very expensive. And so, in the long run, HVDC seems to win out every tine.

But I think -- and this is very very important -- the property rights associated with application of flow control technologies like your phase shifters, like your HVDC, they do not accrue to the owner in an open-access regime.

So even though physically you can control the electrons, from an institutional and

legal perspective you cannot maintain control over those flows unless you have exclusive right to those lines; unless they're built as nonjurisdictional assets essentially.

And so this is very important to understand even -- and something else, came to us a little bit late, but I guess it's very clear at this point.

Going forward and looking at the kinds of benefits. We looked at a lot of the approaches to benefit quantity. Traditional ones are network reliability, and, of course, the lower cost of energy and capacity adjusted for transmission losses.

Some of the things that we are seeing are things that we identified in studies we did for you all a couple of years ago in terms of strategic benefits. Access to new resources; fuel diversity; emissions reductions; improved deliverability; market power mitigation.

There are emerging methods for being able to quantify these in the traditional production costs simulation type of framework. There are people who are doing studies about fuel diversity that look at the impacts on the future

natural gas prices as a result of a more diverse resource portfolio.

The use of environmental adders for emissions reductions and environmental quantifications. Very well accepted. There are efforts to look at the LMP and the shadow prices, look at congestion impacts. And, of course, I know the ISO spent a lot of time looking at market power mitigation in their team methodology.

So these are all methods that can be used, and these are very important to continue working on them.

Two that we don't think are well appreciated are this issue of the role of transmission in limiting the likelihood of extreme bad outcomes. And there's two that I'm very concerned about.

Look at the blackout back, that was an N-5 contingency. Those are not the contingencies that are routinely planned for by the transmission planners. Yet, I would argue that we're very very concerned about blackouts like the one that happened back east.

Market volatility. Another, again, high consequence, low probability type of outcome.

Nobody would have predicted 2000/2001. It was a terrible event. These are the kinds of things where the traditional methods for handling these, the traditional risk assessment methods, expected value calculation, you multiply the potential consequence in times -- they don't really capture society's risk aversion to avoiding extreme bad outcomes.

This is something we think is under-recognized. Yet I think any of those involved in the political process would recognize the value of trying to be proactive about. We are going to recommend more effort be spent on trying to take these things into account in future transmission planning activities.

In our work we've done a limited -- we've started work to try to figure out how you might do that. In terms of the market events really we're looking at the social benefit for mitigating bad market outcomes, extreme market outcomes.

And there's a lot of things that come from the financial world, value at risk, option value, insurance premium types approaches. The challenges they all face is again when you have

these low probability events. The difficulty of trying to assign value in those situations where the events are rare, unlikely, are not routinely experienced. And so you don't really have a record upon which to build probablistic assessments.

The other one I think that is also straightforward mechanically, but very difficult computationally, is looking at extreme events from the reliability standpoint. Looking at N-3, looking at N-4. And the way we think about it is sort of like this:

You can look at the transmission system and you could run some of these extreme scenarios about extreme contingencies. You can put in some transmission lines. And you can re-run those scenarios and you can see what the consequences would be from these more extreme cases.

I think it's a very mechanical approach, very difficult computationally, as any of those who have done transmission planning in these contingency scenarios can imagine.

Fundamental to this, in addition to the mechanics of this, is, of course, getting consensus over these processes. And a lot of this

is about developing trust, developing relationships about the appropriateness of including these types of benefits; figure out methods by which the preferences, particularly societal preferences, about this risk aversion can be expressed.

One of the ways that this might be just an agreement on a certain type of risk premium adder that we might assign to certain transmission project costs. Another approach is a social rate of discount to calculate a different present value for assets that are essentially public goods in this setting.

So that's where we're at on our research. We've done a lot of outreach. We've spoken at several of the Frontier meetings. We're presenting essentially a draft of our work, coming out today. And we'll be writing a draft report in the next month. We'll be meeting with our advisory committee to get feedback on that. And then we hope to issue the final report later this summer.

With that, I conclude my comments.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Joe. Are there comments from others in the

room or questions?

Yes, go ahead.

MR. BRAUN: Thank you, Madam Chair. Tony Braun on behalf of the California Municipal Utilities Association. Just a very quick comment.

We'd like to applaud, I think, the first recognition of a link between the usage rights and the property rights created in a restructured environment under a financial rights system versus the willingness of people to pay for transmission.

It's the first time in any quasi-official or official document came out where this linkage has been recognized.

And we would urge the Commission to not let it lapse, but at least make clear to other folks that are making decisions that this market structure does have an impact on meeting other goals that we have in the state. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

MR. ETO: Other questions or comments?

PRESIDING MEMBER PFANNENSTIEL: Hearing none, thank you very much.

(Pause.)

MR. McCLUSKEY: We're going to go from

Joe Eto's presentation to a presentation on the four interregional -- or the inter -- regional transmission projects being proposed and considered in these proceedings.

The Frontier Line project, TransWest Express, Northern Lights project, which is by TransCanada, and the PG&E's Canada/Northwest/ California project. So, basically in that order.

MR. ELLENBECKER: Good afternoon. I'm Steve Ellenbecker representing Wyoming Governor Dave Freudenthal. I appreciate the opportunity to appear before the Commission, as I had the opportunity to do a few years ago, and participate in your IEPR process.

Bottomline message from Governor Freudenthal to California is work with us to develop the products that meet your public policy objectives here in California and throughout the west.

Kern River is an interstate pipeline that you're familiar with that provides approximately 20 percent of the natural gas supply used in California to help fuel your economy.

We should look to that opportunity and that example to build interstate transmission

projects that have a similar opportunity in the electric industry, giving us the opportunity to move electrons from resource-rich remote areas to urban load centers just as we do with natural gas.

So, I would hope that you would continue to advocate with us, really, on the objective of building interstate transmission for the sake of building our economy in the west.

Jim Sims pointed to some of the underlying premises for interstate transmission. Many of these were reflected in the purpose of the governors in coming together.

In 2004 the governors of California, Nevada, Utah and Wyoming built upon the findings of the Rocky Mountain Area Transmission Study. Which found that if we upgrade the interstate grid throughout the intermountain west and load resources in resource-rich remote areas, we cannot only reduce rates to consumers in the intermountain west. But if we extend those lines through bigger projects en route through Utah, Nevada and to California, or other states by way of similar example, we have the opportunity to build upon the net benefit for consumers.

The Western Governors Association's

clean and diversified energy initiative found that we have the opportunity in the west to build 30,000 megawatts of clean, advanced, renewable and advanced coal projects in the west; and deliver those to markets. But we can't do that without new transmission.

Interstate transmission has the opportunity to eliminate bottlenecks that limit market development and raise costs. And it has the opportunity to promote the development of wind generation, resources in the west, renewable resource potential throughout the west. And it also gives us an output for advanced coal technologies as we continue to develop and further coal technologies, as you are well aware of the need for, to meet public policy considerations being set by states like California.

By the way, in relation to your statutes, let me applaud those because you make it clear what the criteria for products will be. And by making whether it be renewable portfolio standards or greenhouse gas limits related to, for example, coal technologies, you make it clear what the standard is that we have to achieve.

That gives us a marker through which we

can develop technologies, and then products to move through markets hopefully by way of many successful interstate transmission projects.

The governors that I referenced entered their memo of understanding in April of 2005. It's the first step in a real, I believe, persuasive sequence of events that have transpired.

In February of 2006 the governors' representatives for the four states issued a list of project criteria that we hoped we would be able to work with interstate project developers on to further the screening analysis that was developed in concept by name by the governors and called the Frontier Line, which is a concept for major interstate transmission in the west.

In April of 2006 the major utilities in California, San Diego Gas and Electric, Southern Cal Edison, PG&E, along with Sierra Pacific, Nevada Power and two divisions of MidAmerican Energy Holding Company's Rocky Mountain Power and PacifiCorp, along with support from APS and PNM, joined together and made a commitment to develop the Frontier Line feasibility study over the next year.

That was successfully concluded, as scheduled, on April 30, 2007, with the support of all those companies working together and in coordination with the representatives of the governors in the four states.

Already there has been scheduled on June 20, 2007, an organizational meeting for phase two. I'll get into a further discussion of what will be encompassed in phase two.

The feasibility study process for phase one was -- the objective was achieved through an open stakeholder process; 250 parties or people participated in the process. We developed a screening level study. The stakeholders were active throughout the process. And the costs and benefits of the Frontier Line were examined through this screening level study.

The study was accomplished in three parts through three major technical subcommittees, a load and resource subcommittee, transmission subcommittee and economic analysis subcommittee. And these were the technical drivers; they completed the study. Don Kondoleon of your staff was an active influence in working with governors' representatives in pushing this to push the

companies harder to actually make the work in the three subcommittees as detailed and comprehensive as we could.

And I'll go to, shortly, an outline of some of the work that we will accomplish that's been committed to by the partnership utilities for phase two.

April 30th the feasibility study was published. It found that under a number of scenarios the benefits of the Frontier Line exceed the underlying costs of investment and resources. There were major variables around which the project's success hinges. These include natural gas prices, as you would expect. That would be the most extreme driver as a variable.

We all know that the price of natural gas remains uncertain into the future. But it certainly is a key driver as to whether or not the economics are positive for a major interstate transmission project designed to move diverse resources from resource-rich areas to load centers.

Greenhouse gas adder. I want to clarify that the California utilities require that the Frontier Line screening study for phase one was

based around advanced coal technologies, IGCC technologies, not-pulverized coal technologies. And oddly enough, there's actually an advantage under that scenario for advanced coal technology with greenhouse gas adders over natural gas. So long as you successfully achieve the technology continuum that we're working on to develop the coal technologies that capture, and then along with sequestration, deal with carbon as it relates to coal-fired generation.

So, the Frontier Line, not so much in its original concept, but actually as a reflection of laws here in California, and the insistence of the California utilities is an advanced coal technology project concept in the truest sense. Along with maximum utilization of renewable resources to accompany that baseload generation.

The capital costs for advanced coal technologies, the future that relates to adders for greenhouse gas emissions, and, of course, natural gas, they combine together to set the stage for the criteria and analysis in part that will be further examined in phase two.

But, again, the study has concluded that under a number of scenarios this interstate

project, and I would say, therefore, those like it throughout the west, are justified.

I've identified previously the swing in economics that is caused by assumptions for natural gas, greenhouse gas; but the study concludes solidly that a combination of wind and advanced coal resources move to markets via such a line as the Frontier Line is persuasive in diversifying resources and providing economic benefits to consumers.

The partnership utilities that I have mentioned have decided to move to a phase two for the Frontier Line project. The first segment of phase two will be conducted beginning on June 20, 2007, whereby the partnership utilities have decided to invite back in interested developers. They're going to reopen the door to other companies that may be interested; provide an exit opportunity for those that may choose that pathway. And reconfigure the developers, the partners, for phase two.

I encourage California to actively participate within governors' offices and agencies such as this one, along with the other states in supporting phase two of this study.

The underlying goal for phase two will be the determination of a more specific project in terms of size, scope and scale, location; perhaps a couple of alternatives. But within 18 months to further examine the synergies among regional projects and become more specific about a proposed project identity and location.

I'll quickly go through on this slide, and skip a few of the others that follow. You have those. But we certainly need to identify with more specificity the costs on carbon dioxide along with the capture technologies and sequestration technologies and costs.

Wyoming has a world class wind resource. We need yet better information on the capacity factors for this resource which is certainly one of the strengths of a project originated in Wyoming.

This next point, I had a conversation just Friday with Jim McCluskey of your staff, as it relates to which comes first. Identification of the actual generation projects, or the construction of the transmission.

In fact, what we have to do in phase two is bring together the generation developers with

the transmission developers with the load centers and the load-serving utilities. And I would say one of the weaknesses of interstate projects in the west thus far in some instances is that they have not synchronized the alignment and timing for the construction of new generation with that for new transmission with that for a commitment by load-serving utilities or other companies to contract for delivery of the power.

We have to do a more technical analysis of load flow analysis system flow analysis. These things will be identified and performed in phase two, including more work on cost allocation in cooperation with the work that Joe Eto and his colleagues are doing.

Joe has participated in the stakeholder meetings for the Frontier Line, giving cost allocation presentations throughout our process. And has been a welcome colleague, as I see it, in highlighting the importance of identifying interstate in our instance cost allocation to make such a project possible.

My last slide, and I'll go back to my bottomline suggestion from Governor Freudenthal. We are a state, a power-producing state, an

energy-producing state whose Governor is intent on developing projects and products that meet the public policy criteria set by other states.

We certainly have a world class wind resource, along with our colleague states like Montana. There is no opportunity to fully develop and utilize these renewable resources and the potential for advanced coal technologies without interstate transmission to move the power thereby generated to markets.

We need partnerships across the west. We need your support to take advantage of diversifying our resource base and building upon the potential to use resources like these shown here where the dark areas reflect really true world class resources for wind.

Those are not going to be developed to their fullest potential unless we connect them to load centers. And we need partnerships and collaboration across the west, and interstate transmission projects, to make that happen.

Again, I appreciate being here on behalf of Governor Freudenthal, and look forward to the opportunity to continue to work with California.

PRESIDING MEMBER PFANNENSTIEL: Thank

you, Steve. Questions? Let me just, a couple clarifying questions. What did you say the capacity being investigated for the Frontier Line would be?

MR. ELLENBECKER: From the inception we have evaluated building the project in stages; 1500 megawatts to 3000 megawatts initially. The economics were most positive around projects of that scope and scale around 3000 megawatts.

RMATS, the Rocky Mountain Area Transmission Study, envisioned projects upwards of 12,000 megawatts ultimately. We didn't see in the economic analysis subcommittee continued growth in the economic net benefit as the project became larger. But we have an opportunity to evaluate that in phase two.

So I would focus around the opportunity for projects in the range of 3000 megawatts.

PRESIDING MEMBER PFANNENSTIEL: And then another question. You mentioned that within the next 18-month phase --

MR. ELLENBECKER: Yes.

PRESIDING MEMBER PFANNENSTIEL: -- you're going to be looking at the cost of clean coal, or coal sequestration -- carbon

sequestration with coal.

Where does that stand right now? And do you expect to have some answer to that in that 18-month period?

MR. ELLENBECKER: My intent was to clarify that phase two is going to be conducted over the next 18 months, running an improved analysis of the economics of this project opportunity in a specific location.

I can only hope that we have clearer answers on advanced coal technologies and sequestration. But, in fact, Chairman, I see that continuing to be resolved during the longer permitting and siting phases for a project like this.

Those answers will be improved upon. But until we move the technologies sufficiently forward, including the answers that are so important on sequestration, I didn't mean to imply that in 18 months that becomes crystal clear, as well.

I do hope we have a defined product in the way of a project through cooperation with other projects being proposed, some of which that you are going to get additional evidence on this

afternoon. Or more specifics for this project, per se.

PRESIDING MEMBER PFANNENSTIEL: Well, the 3000 megawatts which right now looks like about the economically desirable level of the project, does that assume coal? Or does that not assume coal?

MR. ELLENBECKER: It assumes a combination of wind and coal resource.

PRESIDING MEMBER PFANNENSTIEL: And so the coal would be, clearly would have to meet the standards for import into California, so there would have to be some level, some amount of clean coal that would meet our standards. So there must be some cost assumption in there about the cost of that?

MR. ELLENBECKER: There is. And that's in the economic subcommittee report. If you would like, I'd be happy to offer to --

PRESIDING MEMBER PFANNENSTIEL: I can dig into that. But I just wanted to make sure that that was in there. Okay.

MR. ELLENBECKER: It is there.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Commissioner Byron.

PRESIDING MEMBER BYRON: Mr. Ellenbecker, good to see you. Thanks for coming today. I saw you arrive this morning.

I was taking a look at the phase one study last week, and it looked like there's about 15 different scenarios that are included there. I'm sure you know the exact number. But it's in that ballpark.

MR. ELLENBECKER: Yeah, that's about 13 too many.

PRESIDING MEMBER BYRON: Is that right?

MR. ELLENBECKER: That's about 13 too many, as far as -- we need to narrow this down and define, as TransWest Express has done, more accurately, a narrowly defined project --

PRESIDING MEMBER BYRON: Oh, I see what you mean. I see what you mean. But there were a number of different scenarios in there. I have not made a comparison, and I don't know that you have, either, but given all the 19 candidates that our staff has identified, based upon the submissions and some others that were identified today, is there any overlap? I mean some of them must be similar or exact, I should say I'm asking you as a question, do any of your scenarios match

up with the 19 candidates and others that have been included today?

MR. ELLENBECKER: I would have to work with your staff to confirm that.

PRESIDING MEMBER BYRON: So you haven't made that comparison, either?

MR. ELLENBECKER: Correct.

PRESIDING MEMBER BYRON: Okay. Understandably. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you very much.

MR. ELLENBECKER: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Are there questions from the audience or on the phone?

Hearing none, thank you, Mr. Ellenbecker.

(Pause.)

MR. SMITH: Well, good afternoon. I'm Bob Smith; I'm the Transmission Planning Manager for Arizona Public Service. And I appreciate the opportunity to be here today.

One good thing for me is it's about 20 degrees cooler here than in Phoenix. Maybe the bad thing for me is that I fly out tonight at 6:30 which is tip-off for the Suns in San Antonio, but

maybe a good thing for them, as they may play better if I don't watch.

Just real briefly a little bit about Arizona Public Service. And I think most of you know this, we are the largest electric utility in Arizona. Could have updated this slide. I believe currently we are the number one fastest growing utility in the country. Just recently overtook Sierra Resources Nevada Power Division in the Las Vegas area.

And last summer our control area load peaked at over 7700 megawatts. And this is significant because it was almost 10 percent over the prior year's peak. It did heat up a little more last summer, but I think it does show the significant load growth in the Arizona area.

We serve approximately 1.1 million customers. And Arizona Public Service has a ten-year transmission plan of over $1 billion. And that does not include the conceptual project which I'll be talking about today, the TransWest Express project.

Now I know, on the surface of things, these transmission projects all sort of sound alike. You know, they're all accessing the

northern Rocky Mountain area, potentially Alberta and a project you'll hear about next. But they're all looking for an ability to transmit remote wind and coal resources into load centers.

The load centers may be California; they may be the Arizona area; maybe further up north on the west coast. However, I think if you look a little closer at these projects you'll find that the motivation of the projects is significantly different. I think that should be interesting to you.

The project we just heard about from Steve Ellenbecker really was the vision of some states, and has been, up until certainly the last year, more of a political process than actual technical study.

Now the footprint utilities have done significant work and you heard Steve talk about that. But I look at it as sort of a top-down project.

On the other hand, the project that I'm going to present to you was motivated by a load-serving entity, Arizona Public Service. It has significant responsibility to meet a tremendously large load increase in the State of Arizona,

looking outside of its borders for diversity and baseload opportunities in the northern Rocky Mountain region.

The next presenter, Mr. Bill Hosie from TransCanada, will give you a little different model yet of what I think would be considered a market transmission model. A company that wants to build transmission and make money selling the services from it.

And I think our last presentation from PG&E probably will seem more like this, a project motivated by the responsibilities of a load-serving utility.

Again, this is the picture showing the dc option. We'll talk a little more about the options later on in the presentation. But it's just accessing the coal and wind in eastern Wyoming; and providing a pipe, if you will, to deliver it into the Phoenix area.

One of the things that I think you can easily see on this slide, and I will point it all out as sort of the busy stuff going west from Phoenix into California, shows you planned transmission projects that will enhance the ability to move energy from Arizona to California.

We believe that our project is very complementary with these. And whether or not we actually get participation from one or more California entities -- I believe, Commissioner Byron, you had asked earlier what's in these projects for California -- whether or not these projects are actually used to meet a renewable requirement or desired renewable capacity levels, we transmission engineers sort of live in a contingency planning world. And, you know, I'm not going to guess whether or not your policies will work in the end or not.

But if you do find yourself in the future capacity constrained, or unable to meet your commitments despite best efforts with internal renewables, or even external renewables, I think any transmission that allows resources more of an opportunity to move across the grid toward California are going to be beneficial to you from a reliability perspective in the future.

So a lot of this we've already heard. Certainly our project, along with all the others, would improve reliability, reinforce the east side; specifically add import capability into Arizona and the southwest. Resource diversity

improvements, economics, all these things you've heard. And we certainly agree with pretty much everything that's been said since I've been here after lunch, anyway.

Specifically in Arizona our resource people looking in the crystal balls are looking at a need to add something on the order of 8000 megawatts of increase. And that's after an assumption of 20 percent reduction in our load growth for demand management and energy conservation. And also a 15 percent renewable energy goal.

So, our project would allow us to actually meet only 3000 megawatts of that. So this isn't all of the eggs. We're going to need some other things in the basket, also.

We believe our project, as you've already heard from some other speakers, is consistent with the WGA, the RMATS report, the CDEAC report. And as we'll talk a little more, and Steve alluded to, we've been working with the Frontier study, as well.

So we first announced our project about a year and a half ago, and again, it was motivation from some decisions from our resource

folks that they needed to look at an option. And the northern Rocky Mountain region and the acknowledgement that there was no transmission out of that area already So we would need to develop transmission.

We performed the feasibility study during 2006. And basically were looking at potentially a five-year period to permit during phase two. Three years of construction, so we believe the earliest the transmission project could come online would be about 2015.

We have put the project through an open stakeholder process, very similar to Frontier. We had a kickoff meeting in November of 2005 in Phoenix. Project updating meetings in March of 2006 in Salt Lake City, and also in June of 2006 in Jackson, where we pretty much presented the results of a technical portion of the feasibility analysis.

We've given updates and taken feedback and input from all of the subregional planning groups. The SSG-WI, which is, as you know, has moved into the TEPPC under WECC, as far as expansion planning processes. The WECC forums. And we have been coordinating with the Frontier

activities as Steve mentioned.

We formed four study groups. We did a transmission technical feasibility, the permitting, which was kind of a high-level overview of the feasibility of some particular, some routes.

Economic analysis group. Actually this we deferred into the Frontier study as far as grid-wide economic studies. APS and the other participants did their own internal analysis.

And then we formed a legal and negotiating group to try and put together an agreement to move forward with phase two, which we do not have that agreement executed at this time.

The feasibility study, as far as the transmission analysis, what you're trying to come up with are cost estimates of your alternatives; an estimate of the losses; and the estimated capacity of the project. So these are the things that you would use to make an economic analysis of, combined with the potential resources, does this make sense to build, compared to your other alternatives.

We looked at three 500 kV ac alternatives. And in order to get the economy of

scale of 3000 megawatts you need two circuits, which also provides your redundancy we believe the ac requires. On the other hand, one bipole dc could also deliver 3000 megawatts. And we did look at one hybrid with ac transmission and a portion of it being dc.

The alternatives to trans terminate the project into Arizona, southern Nevada, the Navajo, which is up in north-central Arizona and the Four Corners area.

I'm just going to run through real quick the three ac alternatives. Basically the idea was to have a separate route so you wouldn't have to worry about losing a corridor and having both the lines go out of service.

So we started at the Dave Johnson Power Plant in eastern Wyoming. The lines come together in central Utah, and then one would go to Las Vegas. We felt there was sufficient wire already between Phoenix and Las Vegas that we could schedule back into the Phoenix area. And then the second circuit goes down to Navajo and on down into Phoenix.

This is very similar except going to Navajo we show the option of going over to Four

Corners and back into Phoenix. And this is just the permutation of going to Navajo and Four Corners.

Again, the dc -- now, realize that the dc we have done no analysis to determine that it will go through western Colorado. If we move forward permitting a dc line we believe that we would have to look at a region probably as far east as the eastern slope of Colorado; and maybe as far west as eastern Nevada.

So we would be working with the utilities in those areas trying to find synergies between our project and projects that they might have, maybe local reliability projects, as Joe Eto alluded to earlier.

And this is just the alternative that shows dc coming down from Wyoming into central Utah. And then a couple of ac lines branching off, one to Las Vegas and one into Phoenix.

Now, sort of the takeaway I think I'd like you to have here is that the ac transmission options are much more capital intensive in terms of cost than the dc option. And, in fact, the losses are greater, also. So both of those things are going to push you to dc. And, again, I think

you heard Joe Eto talk about that, also.

The downside, of course, is that you don't have as much capability of interconnecting with things along the way, whether it's other utilities that might benefit from it, or other resources.

So, overall, transmission study conclusion was that we do have several alternatives that will work for 3000 megawatts. Again, the dc and the hybrid were the lowest cost, lowest losses, and the fewest miles of the line.

Also it was acknowledged that since there is no strong transmission system in Wyoming, that if we were to lose one of these two lines or one of the poles of the dc you would have to trip some generation to withstand that outage.

We did a very high level, really more of an analysis to see any fatal flaws in the permitting. Looked through the various jurisdictions. And we also determined what the process and timeline and budget might be for the phase two permitting process.

And overall, including both the technical transmission feasibility analysis and the permitting, again the analysis supported a dc

alternative. We believe there were multiple alternatives for permitting.

Currently where we're at is we're working with other load-serving entities that are interested in the project. Edison, Salt River project, Tucson Electric, along with the Wyoming Infrastructure Authority, and National Grid, which has proposed to be our project manager, we're negotiating a participation agreement.

And we hope to have this done actually at the beginning of this year. But right now we're looking at maybe the third quarter. The $10 million budget for 2007 is probably lower since we kind of lost half the year to start the permitting.

But more recently, and I think this is one of the reasons that I'm comfortable sort of working through things is that PacifiCorp has had a renewed interest in our project. And we believe there are some potentials to have some synergies between our project and some of the reliability based initiatives that PacifiCorp is going to be having in Utah in the near future.

Again, the five-year schedule. $100-plus-million for permitting, if we do narrow

things down to say, we know we're working in Utah, that number probably comes down. These are just all the things that are included in phase two. And the basic idea is that at the end of phase two we want to have everything we need to go out and construct the line.

And I think this is just talking about our involvement in Frontier. And Steve pretty much went through all this. APS has had reps on the steering committee, on the work groups. We provided data which was used for the transmission costing.

So, in conclusion, the TransWest Express is driven by a load-serving entity need. So we have a need to meet tremendous load growth. And we're looking at this transmission as providing us with one option for future resources to meet that load growth.

We believe it enables renewable wind and advanced clean coal technologies. And we have performed the feasibility study in an open stakeholder process. Our transmission and permitting feasibility analysis basically is complete. And we continue to coordinate with the Frontier activities and the PacifiCorp

transmission plans.

And that's all I have.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Mr. Smith. Questions? Commissioner Byron or Commissioner Geesman. Are there questions from the audience in the room? Thank you for participating.

MR. SMITH: Thank you.

(Pause.)

MR. McCLUSKEY: Bill Hosie's going to speak about the NorthernLights project. It looks like to be, at least, a very interesting project with potential synergies between some of the California -- or at least one California project. And, NorthernLights.

MR. HOSIE: Thank you, Jim. Thank you, Commissioners, for the opportunity to make a presentation on the NorthernLights project to you today. And thank you, ladies and gentlemen, for being here.

The NorthernLights is actually three projects. Each project is about 1000 miles long and consists of HVDC transmission technology. Would carry up to 3000 megawatts each, and cost in the range of $1.5 to $2 billion.

The first project that we worked on we called the Celilo project. It originates in the Fort McMurray oil sands area of Alberta and runs down to the Celilo area in Oregon, close to Portland.

That project was originally conceived to bring oil sands cogeneration energy, wind and in the future, hydroelectric energy from new resources in Alberta. And it also has the capability of bringing energy from B.C. and also -- - has the capability of bringing energy from B.C. through an interconnection point in the Spokane area. And that interconnection point also has the ability to pick up incremental energy from Montana.

We have, and continue to think of, the possibility of extending this transmission line down in California, and have submitted potential routes through the federal 368 process.

Our thinking evolved into developing two additional projects which we call the Inland projects. Both of them extend from the Powder River Basin area in Montana and Wyoming.

The first one, the more northerly one, extends from Montana down to the Las Vegas area;

and the second one from the Gillette, Wyoming area down to the Las Vegas area.

Both of these transmission lines have the opportunity to supply energy to California or to Arizona or to Nevada via existing transmission facilities. And should it be desired, we have the ability to extend the lines on to other locations.

Our economic analysis have shown that the resources on all three of these projects have the ability to be cost competitive with generation fueled by natural gas through combined cycle generators.

TransCanada is a $23 billion pipeline and energy infrastructure company that is well positioned to develop long transmission facilities. We are publicly traded on the New York Stock Exchange, and have a very significant position in the United States. Today we carry about one-third of the gas that serves loads in California.

I won't spend much time on this. This map shows the extent of TransCanada's current gas pipeline system in the dark solid lines; and shows projects under development in the dotted lines. It also shows two LNG projects that we're

developing on the east coast.

And here I would just like to note that TransCanada has significant gas storage facilities and so when I get into the conversation about sequestration of CO2 we have very significant experience with the ability to store gases underground.

Ten years ago TransCanada started development of generation plants. And today we have 7700 megawatts of generation facilities, both in the United States and Canada.

The Inland project, we have recently -- the governors of Montana, Idaho and Nevada have recently signed a memorandum of understanding to facilitate the permitting process, to overcome some of the obstacles that I will talk about later on.

We have signed MOUs with over 10,000 megawatts of generators in the three northern states to begin the process of understanding the economics; and we have actually begun bidding into RFPs in the southwest.

We have been working with the DOE's 368 process. And we have a lot of convergence between our chosen transmission routes and the corridors

picked by the DOE. In some cases we have shortcuts that save substantial distances and costs to the end-use consumers.

The Inland project was looked at in the NTAC studies, and through those, confirmed that there would be -- it would be a low-cost alternative for getting energy into the California area.

Today our focus is on advancing the siting and permitting aspects of the project. And building a consortium of individuals or companies that want to participate in the development of the project so we can move on to the next phase of the project.

The Celilo project we have put an application in to the Alberta ISO to solve certain technical and financial rates issues that exist only in Alberta because of its unique regulatory environment.

We have started the WECC regional planning process with a meeting in Portland. And the NTAC study looked at this alternative in some detail, and compared it with other alternatives, and the NorthernLights project came up quite favorable.

Dr. Michal Moore, an ex-commissioner from this Commission, has written a report for the Institute of Sustainable Energy, Economy and Environment that looks at the economics and economic development benefits of developing the project.

So, there's lots of barriers. And this is not an exhaustive list, but I think many have talked about them today before me. We have the issue of rate pancaking. Who's going to pay for the transmission? Who's going to benefit from it? There's winners and losers, how do you differentiate or make the field a level playing field for the winners and losers -- potential winners and losers?

How do you deal with the environmental and land use concerns? The permitting process is, without a doubt, fragmented. How do you aggregate load generation and government sentiment so it all comes together at one time, so that a project can actually get off the ground?

Some states debate whether resources should come from within the state, outside of the state. And then there's always the concern of picking economic generators and generation that's

effective in meeting the standards of the various states.

How do you get load-serving entities to commit to long-term contracts for a project like this? And without a doubt there's a propensity to study, as opposed to get on with projects. And then in many cases there's a balance sheet concern. Who can actually sign up for a project of this magnitude?

We've tried to answer these questions by establishing a set of principles to build the project by. And the first one is that we want to learn from other regional studies that have gone on. Back to 2000, and through to today, there are several or many studies that have been done. All of those studies confirm that transmission is required. And I think if you look at most of them, the Inland projects are supported by those studies. And so we've learned from those studies, rather than try to reproduce them.

What we have done is put a focus on picking a permittable route. We have routes that do not cross national parks, don't go through aboriginal land, stay away from military land, and avoid sensitive environmental areas. The routes

are a little bit longer, but they're far more permittable than they would otherwise be.

Our intent is to have the project paid for through long-term contracts with load-serving entities and generators. And we want to make sure that there's no customer subsidization or socialization of the costs.

In order to develop a project like this, each state must benefit. And so clearly the states that the project crosses must benefit. But, as well, the neighboring states must benefit. And we believe that we've developed a set of projects where there is benefit, widespread benefits to the various different jurisdictions.

There needs to be a win/win for renewable and coal-fired resources. Our belief is that a project that is designed simply for renewable energy won't be economic. Because nobody is willing to pay any price for their energy.

So we've developed arrangements whereby renewable energy will be able to use the facilities as well as baseloaded generation.

One of the aspects of our project is that we are planning to use dc technology and it

does minimize the rate pancaking issues that can be a real show stopper for moving energy long distances.

DC technology insures the lowest cost for the end-use consumers, and it's more easy to integrate with existing systems than ac developments are. And it has a significant reduced environmental impact or land impact.

This is showing, by this drawing, compliments of ABB, it shows a 3000 to 4000 megawatt ac system in the top left corner, consisting of three 500 kV lines. In comparison to a dc line with 3000 megawatts capacity on the bottom right hand. So this speaks loudly to the beneficial effects of moving to dc technology.

Today NorthernLights project does not propose to go into California. We believe that we can build a project in six years from when we start going full out, three years for permitting and three years for construction.

And that's somewhat different than Bob's schedule. We have worked with the BLM. We have a BLM project manager assigned to the project. We're currently working on cost recovery agreements for the Inland project. And we've

worked through detailed schedules with the BLM and believe that a three-year permitting process is reasonable for this orientation because we are missing -- we're not going through a lot of the difficult-to-permit areas.

So, we will be on California's doorstep. And each of the projects has the opportunity to extend into California should the system situation evolve so that California wants to see that happen.

The projects will facilitate inter-regional trade and support the reliability of the interconnected system. The projects will provide people at the load end with a huge set of resources, integrated wind, clean coal, synthetic gas, cogeneration, geothermal and large and small hydro projects that are still undeveloped in Canada.

It'll give Californians and people at the load end of the line opportunity to choose from a wide variety of resources and a wide variety of innovative generation developers.

It provides lowest cost access for transmission of this kind of distance. For the over 500 miles dc is the technology that is most

economic. And so these projects will provide the lowest cost opportunity to connect to remote resources. And with the dc technology there'll be reduced environmental and land use impacts.

That's as far as I wanted to go right now because what I've done is I've answered the panel questions in the remainder of my handout or presentation. So I'll just leave it for the panel discussion, so I'm ready to answer any questions anybody may have.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Mr. Hosie. Very interesting presentation. I just want to make sure I understand the relationship between your three lines and the others that we heard about or that we will hear about today.

It's independent. In other words, even if those others go forward, TransCanada is still planning to go forward with the NorthernLights?

MR. HOSIE: Yeah, if we start in the north, the PG&E project is configured primarily to pick up energy from B.C. with some opportunities to pick up some energy from Alberta. The Celilo project is primarily designed to be able to get energy out of Alberta, and to interconnect the

Alberta market with the Pacific Northwest and California market.

Today Alberta is really disconnected from a market perspective. And we see that there's huge opportunities interconnecting those markets. So we think that we would go ahead. We could go ahead in parallel. The needs are huge. So I don't see that one project trumps another project.

And I think the same may be true of the Frontier project in that the Frontier project will work over the next while to figure out exactly what they want to propose. And since Frontier plans to go into California, it will really need to depend on the coal-fired technology evolving beyond where it is today.

So, we don't see huge conflicts. We see huge need and we're stepping up to fill those needs.

PRESIDING MEMBER PFANNENSTIEL: But the actual construction will depend on having contracts, I assume, in place before you start construction?

MR. HOSIE: That's right. Most merchants would not go ahead with a project of

this magnitude without some underpinnings in --

PRESIDING MEMBER PFANNENSTIEL: So that, I guess, would demonstrate the need if people were to sign the contracts?

MR. HOSIE: That would be one argument that there is a need. And then the other, I think, would come through the WECC and the studies that TEPPC would do on a project like this to demonstrate the economics to the west.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Commissioner Byron, Commissioner Geesman. No other questions here. Any others?

Thank you very much, Mr. Hosie.

MR. HOSIE: Thank you.

(Pause.)

MR. McCLUSKEY: Steve Metague of PG&E is going to discuss their Canada/Northwest/California project. And I'll turn it over to Steve.

MR. METAGUE: Thank you, Jim. And thank you, Commissioners, and Advisors, and all of you who have joined us today. I'm pleased for the opportunity to share with you a transmission project which I have the honor of being the Project Manager for. I think it's an exciting project.

I think that this is the last you'll hear of the day, but it is the newer kid on the block. Those who have preceded me have a little more time under their belts. And their projects perhaps a tiny bit more mature. But I think we're making huge progress. So, with that, I'd like to move into our discussion today.

Let me give you kind of a quick history on this project. We really kicked this off in August of 2006 with a notice that we wanted to begin a WECC regional project review; and received a tremendous amount of interest from a broad group of stakeholders. And we have solicited their help as we move forward with this project.

What the project represents is kind of three major benefits. I'm sure there are many others that we've talked about so far today. but this project is designed with a real eye on renewables. And that is one of the main drivers for this project.

We believe that the project has a lot of opportunities to improve reliability throughout the western states that it comes into contact with. And we believe that there are economic benefits to be derived from a variety of

participants in this project.

Now, the next -- what I wanted to do is just give you an idea of how we're organized and how we're proceeding.

Now, this project has a steering team which I'll introduce with the next slide. There are six, a total of six utilities who are driving this process. I'm the Project Manager. And we have three major committees that are well engaged and have been working since December of 2006. We did kick this whole project off with a large stakeholder meeting in December 2006 where representatives of the Commission were present.

We have a loads and resources group; a technical analysis group; and an economic analysis group. They're the three committees that are underway right now. We may be engaging other committees as we proceed. But we have a lot of work to do still, but we are making good progress.

Now, let me introduce the structure a little bit deeper. This is the composition of the steering team. You'll notice we have five utilities who are U.S. utilities, who are working together to develop this project from northern California to the Canadian border.

Some characteristics of those utilities are that they are load-serving entities; we believe they have footprints that could very well be impacted by the project we're considering. And one of the criteria we also used in looking at this steering team is that we believe these are utilities, that given a good project, are willing to actually invest in that project.

I'm also pleased to announce that we have a public and private partnership here. TANC is in the room with us here today. And they have joined us on the steering team.

The other thing I'd mention, BCTC, British Columbia Transmission Corporation, one of the reasons why it's very important, in our view, to have them on the steering team, is that for success we need to have complementary transmission development north of the border. And we have been working with BCTC with that objective in mind.

These are the committees. I think the committees are well engaged. The first step we wanted to do is take a look at where loads and resources are, and try to look for some information that helps shape the contours of the routing of this system.

As I showed you on the first chart we have both an undersea route that's being explored, as well as an overland route that's being explored. But we're pretty much staying to the Washington-Oregon-Canada. We do have a spur that could go a little bit further east.

But the loads and resources group has been looking at that area and identifying, if you will, resource bubbles, which I'll show you in a moment.

Technical analysis committee is working on the next step. As some of you may be aware, the NTAC study of May of 2006 already showed that some of the configurations we're looking at could make a lot of sense. We're trying to dig a little bit deeper at this point, just to test those assumptions and make sure that still pans out.

And ultimately we're looking at the economic analysis because we're still at the stage of wanting to be sure that this project does make sense.

This is one of the early outputs from the loads and resources working group. It's an attempt to take a look at where resources might be that could supply the needs, particularly the

renewable needs of California.

We are looking particularly at British Columbia because of the very very strong resource base for renewables there, plus the advantage of potentially having hydro for storage and shaping, which seems to us to be a natural complement to any kind of transmission line that we're trying to build for renewables.

Just wanted to tick off a few of the upcoming milestones. We have a -- our next steering team meeting is in July. And that's here in San Francisco, but we do have, we call it the big tent meeting. August 2nd we're scheduled to have an opportunity for all the stakeholders to come together at a large meeting in Portland where we'll be able to present the draft results of all of the committee work.

The loads and resources committee has just about completed its work. It's made the handoffs now to the technical committee, as well as to the economic evaluation committee. And we're aiming to have a first draft of all of that report available by August 2nd.

Then after absorbing comments and fine-tuning what we've done, we do want to finalize the

Committee reports and submit the final WECC regional report by November 1st.

Let me put that into the context of the project, itself, though. There are many many phases to this project and many pieces. This is clearly a simplified view of what we're trying to achieve. And you'll see that we have a rather aggressive date of 2013 for operation for this project. We have lots of work to do.

And one of the things we're starting to explore right now is some of the early siting and permitting investigations that need to be done. Some of that help with something that the CPUC has authorized in February of 2007, which allows us and permits us to actually expend some monies to begin that early work.

I think I'll just wind up with an opportunity to -- with our advertisement. This is where you can find out a lot more about us. And that's really it. I think I'm available for questions.

PRESIDING MEMBER PFANNENSTIEL: Pretty ambitious timeframe. I'm going back to your earlier slides in terms of the different route that the line might take.

Seems like there's a big difference in your permitting structure depending on which way you want to go, and that's going to affect the timing a lot. So, 2013 is the most optimistic, or is it a -- have you done a number of different scenarios and that's 2013 seems pretty reasonable? Or how do we think about that?

MR. METAGUE: I think that's a great question. And one of the things that we're trying to achieve is a very quick and narrowing down of the options. And I think you've heard some of the challenges from the previous speakers of when you have 15 different alternatives you're evaluating.

Our goal is to try to reach a service plan this summer; really trying to narrow this down so that we don't focus too much activity and too much investigation into areas for permitting and siting purposes that we really don't intend to pursue.

That's one of the reasons why we want to take a quick look at the economics and technical feasibility of these projects, to be able to do that narrowing.

PRESIDING MEMBER PFANNENSTIEL: And going up to the British Columbia renewables

potential, the idea of matching hydro with presumably wind, what's the untapped hydro potential up there? Are you looking at that? Or are you looking at existing hydro and diverting it from other uses down to California?

MR. METAGUE: Excellent questions, and I'd just say that generally the focus of this project is incremental renewable development, which include both wind and hydro.

Now, there's a lot more work going on which I'm not involved in with our, I'll call it the merchant side of PG&E, that is looking much more deeply into the resource picture in British Columbia.

PRESIDING MEMBER PFANNENSTIEL: So the wind development is both outside of your responsibility, but you assume that that is going on apace. So, the wind project would be there by the time you did a go/no-go with the transmission?

MR. METAGUE: Right. There are going to be many check-in points along the way as I foresee it. And one of the problems that any major regional project, I think, faces is trying to coordinate the development of the resources -- in this case development of the complementary

transmission on the northern end.

I think on the southern end that is in California you heard Ben Morris this morning, as well as the TANC representatives, describing project that very much complement this for bringing the power from the northern California into some of the load centers. But there will also be some challenges with coordination with transmission development within Canada.

So we will be doing a lot of very intentional check-ins as we go to make sure that we're as best possible trying to coordinate the development of all these things to reach an optimal point for actually constructing the line.

PRESIDING MEMBER PFANNENSTIEL: Great, so we'll know more this summer?

MR. METAGUE: Absolutely. That'll be another good checkpoint.

PRESIDING MEMBER PFANNENSTIEL: Thanks. Other questions? Commissioner Byron.

PRESIDING MEMBER BYRON: Yes, thank you. Mr. Metague, a couple of questions. Please remind me how many megawatts are we talking about for these two possible routes?

MR. METAGUE: Yeah, I think we're

looking primarily at a 3000 megawatt development. Now, we are looking at some scenarios that could have 1500 or 1600 megawatts, but primarily I think it's best at this point to think of this as a 3000 megawatt project.

PRESIDING MEMBER BYRON: Okay. And please correct me if I'm wrong, but I haven't looked into this for about three or four years, but my recollection is that we don't have a whole lot of submerged 230 kV lines throughout the world. I don't think higher than 115 kV. And those that are underwater, they don't have a good track record with them, either.

So my guess is that you've got to have the technology catch up to what you want to do here.

MR. METAGUE: There are definitely some challenges that we're looking at very closely right now. We are working with Seabreeze, who is one of the developers of this technology, as part of our technical committee and providing very helpful input along the way.

But we do have many challenges and many questions we have to assure ourselves of as we go through this screening process that we're going

through in these next few months.

PRESIDING MEMBER BYRON: Is it correct, though, that we don't have any 230 kV submerged at this point?

MR. METAGUE: This would surpass by a great deal the largest undersea cable project in the world.

PRESIDING MEMBER BYRON: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Anything else? Any other questions in the room? Thanks, Steve.

MR. METAGUE: Great. Thank you.

MR. BARTRIDGE: Okay, next up we're going to have a panel discussion. I'll let Jim do the introductions here. And the questions are on the board.

MR. McCLUSKEY: We're going to have two panel discussions. Both are going to address two sets of questions, or one set of questions.

Well, first of all we'd like to get some idea of what they perceive to be the potential issues, barriers, impediments, et cetera, and the benefits and costs of the projects that they're proposing; or at least the project proponents have proposed. A look at the issues there.

And secondly we'd like to know, to have them answer two questions. One is what contributions can these projects make to the state policy objectives, including renewable resource goals and GHG legislative standards.

The second one is how do recent federal and WECC trends and policies help to hinder or achieve state policy objectives.

We're going to have two workshops -- I mean two panels, I'm sorry. The first one will consist of representatives from DOE, the CPUC, the Cal-ISO, LADWP and TANC.

And the second one will -- those are folks who haven't made presentations thus far -- and the second will use panelists who've already made presentations.

So, if we could have the panelists from DOE -- or the folks who want to participate in the panel discussions from DOE; let's see, and I think the folks, Michael Brairton from DOE, not sure who the CPUC would be, not sure -- I think Gary DeShazo's going to speak for the Cal-ISO. And I think we have a representative from L.A. and TANC is Jim Beck.

Okay, DOE could lead this off.

MR. BRAIRTON: Thank you for having me here today. My name is Michael Brairton with the Department of Energy Office of Electricity and Delivery and Energy Reliability.

We have some recent news that I'm sure everybody's been paying attention to regarding the release of our draft national interest electric transmission corridors. So I'll talk about that for a little bit, and then some of the other activities that Congress directed our office to do in EPACT 05.

As part of EPACT 05 we were required to issue a congestion study after the first year of that enactment of that law to identify areas where there is congestion currently in place that's adversely affecting consumers. We issued that report in August 8, 2006, and we'll do so every three years after that.

In our study we identified several areas of congestion. And first we looked at two critical congestion areas which was mostly the midAtlantic. And then the second area was pretty much southern California.

We had several congestion ares of concern. This dealt with areas where we felt that

there needed to be further investigation whether there was actually adverse consumer impacted. And then the final portion was additional congestion areas where if new generation was built there would be a problem getting that generation to the load centers.

Based on the study and comments that we received from stakeholders, affected states, and others who wished to participate, we made a recommendation to the Secretary to issue a draft national interest corridors on the two congested, critical congestion areas that we identified in our congestion study in August 2006.

The one most impacting California would be the southwest corridor which includes southern California, Arizona and one county in Nevada, which is Clark County, basically the Las Vegas area.

The approach that we used was a source and sink approach. We looked at geographic areas. Basically the critical congestion areas that we identified are the sink areas. And the source areas are where this potential for additional generation bring into the sink area, but there's congestion to get that generation into the

critical congested areas.

We used a county boundary approach. We did this because everybody knows where the country boundary is. And there would be assurance by potential developers that they knew that the project would be in a corridor.

And we proposed that the corridor would last for 12 years unless it was determined by the Secretary that they needed to be revised. And it would not be terminated while FERC was considering a permit application or overseeing construction of a transmission project within that corridor.

Jumping a little bit to the southwest corridor specifically, what the draft southwest area national corridor looks to do, it takes the Los Angeles/San Diego area as the critical congestion area as the sink. And we are attempting to try to connect sources of area bounded to the north by the Tehachapi wind resource area; west by the Key Substation around Las Vegas; and Palo Verde-Arizona, east of Phoenix.

Kind of help understand what exactly these draft national corridors would do if they actually became final after our 60-day comment

period which closes July 6th of this year.

If these corridors become final it would give an applicant an opportunity to use FERC as a backstopping authority if the state was unable to act on a application, or did not act within one year of the application being filed with the state.

There was a couple things I wanted to address on some of the presentations I heard earlier that kind of concerned. First of all, the draft designations do not identify or endorse any transmission project. That was not our intent.

Our intent was to provide an area where maybe a transmission line seems to be a good choice, maybe not. We don't feel that there's any one solution to the problem in each region. Energy efficiency, demand response, it's up to those planning entities that are involved in that region to decide what is best for that corridor.

The other thing I wanted to address, too, in case there's some rumors out there. We are, indeed, having our hearing on San Diego on Thursday at this time. I know there was some suggestions that it may have been postponed, but that's not true.

Some of the other things that DOE, specifically office of electricity, is working on is the 368 corridors, part of EPACTT. We are the co-lead on preparing that EIS and we've been working closely with the CEC. The feedback we've gotten from the CEC has actually been very helpful in our determination. And we continue to look forward to having the CEC as a partner as we move forward.

We're very close to issuing our EIS. And based on the feedback we've decided to have two hearings once that's been released in California; one in the north, one in the south.

The other item under the EPACT 05 that our office has been charged with is 216(h). This would make DOE the lead agency coordinating federal authorizations with other federal entities that are in charge of providing permits to transmission facilities.

Right now we have not issued any type of regulation or guidance on how we would proceed. We are working under an MOU that we signed with the agencies that would be involved in providing permit applications. And at this time we are just collecting information, trying to find out what

projects are out there. Helping to understand what the agencies such as BLM, Forest Service, what their process is in terms of doing an EIS, so that we can make sure that we work closely together and actually make 216(h) work.

I'll leave it at that. I'd prefer questions. And, again, thanks for having me here.

PRESIDING MEMBER BYRON: Well, if I may, just a quick question. You said the comment period closes down, these NIETCs become final July 6th.

MR. BRAIRTON: The comment period closes July 6th, --

PRESIDING MEMBER BYRON: Okay.

MR. BRAIRTON: -- but that does not mean it becomes final. We will take, depending on the number of comments received, which we expect to be a very high volume if it's similar to the congestion study comment period, it will probably take us several months, probably get fall to make a determination whether these should become final; they should be amended; or not to do anything at all.

PRESIDING MEMBER BYRON: Okay. So it could be a number of months after that, then?

MR. BRAIRTON: Yes.

PRESIDING MEMBER BYRON: Okay, thank you.

MR. CAUCHOIS: Good afternoon, Commissioners. My name is Scott Cauchois of the Division of Ratepayer Advocates at the PUC. But the first thing I want to make clear is today I'm speaking as the Co-chair of WECC's Transmission Expansion Policy Planning Committee. And I am not representing any views or opinions on behalf of the PUC or DRA.

And I think you've heard an introduction to what's called TEPPC today, but I wanted to be clear on what were trying to do, and what we plan to do, and I'll be able to answer questions you may have as a result of some of the comments on studies you've heard today.

Our basic mandate -- we were formed just 13 months ago, and with three primary responsibilities in the west. One is regarding data; it's to oversee development and management of a common database for economic analysis of transmission needs in the west.

Two, providing policy and management of the regional planning process across the region.

And three, guiding analyses and modeling for western interconnection economic transmission planning projects.

So, sort of segueing into FERC order 890 which you've heard a lot about, we are -- our goals are to provide an impartial forum for transmission analysis, maintenance of data. Our goal is to maintain a completely open, high quality, publicly available database.

In terms of coordination around the region, for now practically, almost for a year now we've been holding -- we hold monthly coordination calls among the subregional planning groups in the west, and other stakeholders, many of whom are here in this room today.

In terms of 890 compliance we have posted for the use of transmission providers in the west who are the ones who will be posting their strawman proposals May 29th at FERC, we have posted a regional -- essentially a regional strawman for how the western process works, for providers to include in or refer to in their filings.

And then responding to Mr. Brairton on my left, we will be picking up responsibility for

what was first done last year by the Western Congestion Assessment Task Force, which did the congestion study that DOE used as a large part of the input into their draft corridors.

We will be responsible for the 2007 update. And in that sense we'll be coordinating with other parties in the west and with DOE to get that done sometime this summer, I assume.

MR. BRAIRTON: Yes.

MR. CAUCHOIS: And as Mr. Brairton also said in terms of endorsing particular projects, TEPPC does not see its role and will not be endorsing particular transmission projects.

Rather in our first biennial assessment, looking at the whole western region transmission plan that'll come out early next year, I think as Bill Hosie said, we will be looking at various transmission proposals and concepts, many of which you're hearing about today, some of which you haven't. And we will be looking and examining the economics of those projects. We will be publishing a report.

What we hope to be able to find and identify are projects that are most economically beneficial for the west. And in answer to, I

guess, question number two up there, state policies, renewable goals, greenhouse gas policy, energy efficiency, demand response are very much on our minds as we analyze the need for large interstate transmission projects.

And we will keep these in mind and explicitly look at these as we model the system in various configurations trying to get a robust picture of what looks good for the west.

So, thank you very much. If there's any other questions I'll be glad to answer those at any point.

PRESIDING MEMBER BYRON: If I may, you mentioned there were a number of other projects, or at least some other projects that were being considered that weren't being discussed here today.

Can you think of any offhand?

MR. CAUCHOIS: These are projects that may not have as direct an -- these are other projects in the west. They may not have a direct impact on California, but what's interesting about some of these is that they are being built also to tap into some of the big resource areas that you've seen identified.

One would be Sunzia, looking at bringing in renewable power from eastern New Mexico to the Phoenix load areas. The eastern -- what I call the eastern Nevada intertie, but it's actually comprised of different projects, would tie southern Idaho, eastern Nevada down to Las Vegas. And part of the Nevada IRP plan calls for renewable development, particularly on the east side and southern part of Nevada, with the idea of being able to use that, but export it also to other states.

So there are -- I think you've heard today, the western grid is totally interconnected. When you build something in one place, you're always going to be affecting something in some other place. And in this case there's a lot of interest, I think, by renewable developers to develop and transmit. And a lot of interest in some of the big load growth areas to take advantage of that.

PRESIDING MEMBER BYRON: In fact, while you were answering it, my Advisor slipped me the slide from Mr. Sims' presentation that showed a picture of a number of the different --

MR. CAUCHOIS: Yeah, that's a good

slide. Right.

PRESIDING MEMBER BYRON: Yeah. So how do you do this kind of economic analysis when these are all in various states; you don't have enough information about any particular one.

MR. CAUCHOIS: Well, I think it was Rich Lauckhart from Global that brought up earlier, you know, we have to go through the same sort of exercise as -- first of all, the WECC already puts out a five- and a ten-year assessment through its planning coordination committee.

And our assessment will be building off some of the inputs that they use on loads and resources, load forecasting, load modeling, wind modeling, and so on and so forth.

But, you know, to build a basecase we have to do the same thing you do at the CEC in forecasting. You have to make some determination about, you know, what to count in your basecase in terms of loads, in terms of generating resources and transmission.

And then you need to assess via sensitivity or scenario analysis, you know, what additional projects beyond those, or less than those, would make more economic sense say than

your basecase.

PRESIDING MEMBER BYRON: Thank you.

MR. CAUCHOIS: So it's a lot of modeling, but I know you have staff that goes through this in spades.

PRESIDING MEMBER BYRON: I guess I'm just really acknowledging that it's not an easy job.

ASSOCIATE MEMBER GEESMAN: Scott, who else is on your committee?

MR. CAUCHOIS: Our committee right now is 17 members; some are in this room. I think Gary DeShazo right down here from the ISO; Jim Feider, City of Redding from TANC; Dian Grueneich, Commissioner at the PUC; Bob Smith, APS, who's already been up in front of you. We have a representative from each of the subregional groups. We have a new environmental representative named Tom Darin, who's an attorney hired by Western Resource Advocates to specialize in transmission. I'm skipping over a number, but there -- it's a very representative group around the west.

A number of people from different types of entities in California. A member from Edison,

Luis Pando. So.

ASSOCIATE MEMBER GEESMAN: Do you take votes, or do you operate by consensus or what's your operating process?

MR. CAUCHOIS: Yes, we do take votes on those things that require a vote. And there are certain things, according to our charter, that we have to take all the way up to the WECC Board.

And for example, before we put out any western regional assessment, we are to provide that to the board and inform them as to what it is. And they have to vote to accept that and give us authority to publish that.

ASSOCIATE MEMBER GEESMAN: Thank you.

MR. FLYNN: Good afternoon, Commissioners; Tom Flynn with the Public Utilities Commission. Scott's colleagues over in the energy division, focus on transmission issues; I'm currently the PUC's Project Manager on Tehachapi.

There's been a lot of discussion today, of course, regarding or on the subject of the procurement of renewable electric generation and the management of greenhouse gases. Certainly does create a lot of challenges when it comes to the planning, permitting and construction of

transmission.

And I take note of that when I look at the first question up there; it has in it the word contributions. And as we, you know, undertake these efforts it's certainly clear that proactive transmission planning is a very important part of that effort.

And the fact that these projects like these are being assessed, evaluated, resources on the other ends of some of these lines are being identified and assessed is very important. And it's a very significant component of planning. And something, I think, that in my view is pretty valuable in that regard.

As you know, at the PUC we're evaluating, involved in efforts with regard to the IOUs, evaluating our instate and nearby renewables and associated transmission options or solutions that relate to those.

But we're also engaged in a much broader western level planning efforts at the WECC, as Scott just summarized. But that said, you know, I don't think we're ready to commit to some of these more distant opportunities until we have not only reasonably pursued renewable opportunities instate

and nearby, but also have gained a better understanding of the resources associated with some of these projects, as well as the potential benefits of some of these projects and their cost, as well.

So we recognize the value of, certainly recognize the value of keeping updated on these efforts, and keeping apprised of the resource and transmission opportunities that are farther afield. And appreciate all the efforts that are going into this proactive transmission planning that's resulting in some of these ideas and transmission concepts that we're talking about today. As well as the contribution that, of course, of this workshop and the IEPR plan in that process, as well as the CEC's strategic transmission plan, I think, plays an important role in that, as well.

Thank you.

ASSOCIATE MEMBER GEESMAN: I saw, I believe it was an order from Commissioner Grueneich -- it may have been something adopted by the full Commission -- last week that was designed to cut the prepermitting planning time for projects in half.

Can you provide us any insight as to what's anticipated there?

MR. FLYNN: Actually, I'm not familiar with that. I'm actually not up to speed on that; I apologize.

ASSOCIATE MEMBER GEESMAN: How much of your planning process is independent within the CPUC Staff, and how much is really more derivative of asking the regulatees to submit certain plans?

MR. FLYNN: Are you asking to what extent we run power flow and stability studies inhouse, or to what extent we rely on that type of analysis from the utilities?

ASSOCIATE MEMBER GEESMAN: That would be a good start.

MR. FLYNN: Well, certainly we rely very heavily on the IOUs to perform technical analysis as well as our reliance on the ISO's role in analyzing transmission proposals, and the reliability and economic and renewable related benefits that come with some of those projects.

And we, of course, have a lot of technical expertise inhouse, myself included, that has the background to perform independent reviews of some of that work. So that we're not

completely relying on the information provided to us by the utilities and the ISO, for example.

ASSOCIATE MEMBER GEESMAN: How large a planning staff do you have?

MR. FLYNN: I'd have to actually get back to you on that. I don't actually know.

ASSOCIATE MEMBER GEESMAN: Thank you.

PRESIDING MEMBER PFANNENSTIEL: I guess I didn't hear the answer to your second question up here, about recent federal and WECC trends, and you know, how do they help or hinder. There's a lot going on right now, and I'd really like your assessment of whether that's been helpful to what we need to be doing in California or not.

MR. FLYNN: I'd like to see if someone else on our staff who's been more involved in those efforts might like to address your question for you, Chairman.

MR. CHASET: Good afternoon; I'm Larry Chaset with the legal division of the Public Utilities Commission. I've been working with FERC and DOE, and to some extent WECC, on these issues that we're addressing today.

I would say that the process that's going on at WECC is extremely useful. The

regional planning process that TEPPC has initiated, and that is being conducted on a more granular level by the various subregions within WECC, I think is going to lead us within a year or two, at the most, to a comprehensive plan for transmission development in the west on a cost effective basis that takes into account explicitly a lot of state policies and goals.

So, I would focus our efforts, I would recommend that our Commission be very actively involved, continue to be actively involved in that. And I would encourage your Commission to participate in the California subregional planning effort that's just getting underway. Gary hopefully will talk about that in a few minutes.

This is going to be, we believe, the single most fruitful avenue for planning for the needed transmission development in California. Because it's not only going to be looking at what we need in this state to meet state goals, but it's also going to be coordinated carefully with the three adjacent subregional control areas, Columbia grid to the north, west connect to the east, and NTTG to the northeast.

California or ISO abuts all three of

these other subregional groups in the west. So we would hope that as this process evolves, we're going to see a really first rate transmission planning output.

And so, you know, it's really good. And, of course, FERC order 890 has directed us to be much more specific and focused in how we perform this planning analysis. The strawperson is going to be submitted this month. We're going to have some meetings in June. There will undoubtedly be comments back to FERC on the strawperson.

And then later this year all of the entities are going to actually have to submit specific transmission planning protocols answering all of the nine criteria that are set forth in order 890 indicating what elements have to be incorporated in open and transparent regional transmission planning.

So we think that's a very good direction for us all to be taking. Obviously this is a FERC initiative to some extent, but in the west we've been engaged in this since well before FERC issued order 890 in February.

So, in that regard I think the federal

efforts have really helped the achievement of state policy objectives. I hope that answers your question.

ASSOCIATE MEMBER GEESMAN: I wonder if you could address the DOE NIETC designation. Would that fit the same conclusion that you just drew?

MR. CHASET: I would not say that it does. I think that the corridors that are identified are far too broad. I think --

ASSOCIATE MEMBER GEESMAN: They said they didn't identify corridors, they identified --

MR. CHASET: It wasn't a corridor, the EPACT required DOE to identify corridors. I think one of the main concerns that we had articulated in our comments on this was that there were specific areas of congestion identified in the WCATF study in 2005. There was an east-of-the-river constraint, east-of-the-Colorado-River constraint; a west-of-the-Colorado-River constraint.

The STEP subregional planning effort that had been ongoing a number of years ago identified a particular project to alleviate that constraint, that project is the Palo Verde-Devers

line that Edison proposed running into central Arizona.

As you know, our Commission has already approved the California portion of that line. We're hopeful that Arizona will approve its portion. Once that line is fully approved and under construction, we believe that once it is constructed, it will significantly alleviate the particular congestion that was identified at the STEP study, such that to create, as it were, a smear in lieu of a corridor, you know, covering most of southern California, 75 percent of the population of Nevada and, you know, central Arizona is probably an overreach.

ASSOCIATE MEMBER GEESMAN: Which suggests, at least from my reading, that they're not particularly impressed with how California has discharged those responsibilities historically.

MR. CHASET: I think that they did not have the advantage when they took that action of the recent actions of the California Public Utilities Commission in approving some very important pieces of new transmission, that as your Commission is aware, we have approved in the last couple months.

ASSOCIATE MEMBER GEESMAN: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

MR. FEIDER: Good afternoon; my name is Jim Feider. I'm the Director of the Redding Electric Utility; and I'm serving in that role here this afternoon, as well as the Chairman of the Transmission Agency of Northern California. I thank the Commission for having me here this afternoon.

I want to touch on three areas that relate to the two questions on the screen, but before I do I know that Mr. Beck, the other Jim from TANC that was here earlier this morning, introduced the Commission and the record as to who TANC and its members are.

But I want to emphasize a couple of points in that. TANC's members are load-serving entities that serve approximately 6000 megawatts of load in the greater northern and central California area. And in the 1990 timeframe we invested roughly $400 million in 500 kV transmission in order to better serve our customers.

And then several of the TANC members a

couple years later invested money in the Desert Southwest transmission, which was also one of the more recent 500 kV additions to the State of California.

We see a number of barriers to going forward and building transmission, but we are encouraged by some of the progress both at the federal level, as well as at the WECC level on policies that will facilitate getting infrastructure built.

But first of all, as load-serving entities we approach resource planning as an integrated process. And in order to do quality resource planning to get energy to serve our customers, we look at it first and foremost from that standpoint. And then transmission becomes a subset of that.

We've illustrated the need amongst our members for diversity in fuel supply, diversity in energy types. And we firmly believe that that diversity adds value to our customers. We also look at it from a cost effective standpoint, and also from a durability standpoint.

And when I say durability I refer to what we call ownership-like rights, or long-term

transmission rights. I'm very encouraged by one of the earlier speakers today to hit that point very hard. We think that's going to be a critical ingredient going forward, to get people to step up to make investment in transmission.

By way of example, three of the TANC members, Modesto Irrigation District, the City of Santa Clara and the City of Redding, went into the renewable market, if you will, and bought the entire output of a 200 megawatt windfarm in Washington State. We began delivery of that project to our respective loads and customers in October last year.

If we had not made the investment in transmission and retained those property rights, whether or not we would have made that decision the way we made it would be very problematic.

One of the areas and barriers of building transmission, of course, is the environmental and regulatory permitting process. One of the big challenges out there is to achieve what I would call a balanced environmental decisionmaking.

As you know, we have to take into account, through a permitting and environmental

process, whether it's CEQA or NEPA or both, we have to take into account land use decisions, endangered species decisions, wetlands decisions, and we have to coordinate and cooperate with so many resource agencies it's almost mind-boggling, from the Bureau of Land Management to the U.S. Forest Service, Fish and Wildlife Service, and a few of the state agencies like State Fish and Game.

These entities are very critical going forward in order to build additional infrastructure.

And then kind of overlaid with that is the so-called regulatory approval. If our partners in projects like Pacific Gas and Electric Company have their own regulatory process to go through, that adds additional complexity.

I would say, however, that some of the federal policy that's been advanced here in the last year or two, I think, will facilitate that. We're encouraged both by the Energy Policy Act that puts DOE in more of a collaborative role with some of these resource agencies like BLM. And anything they can do in that regard I think will help in the long run.

Also the Energy Policy Act, as you know, encouraged -- or required long-term transmission rights. And we think the market design, whether it's in California or the entire west, needs to keep that in mind in order for people to make those long-term investments and have that quality resource planning capability.

Also at the WECC level it was mentioned the TEPPC group; I am a new member on that committee. My first meeting will be this Friday in San Diego, so I'm looking forward to participating in that arena.

TANC has been promoting WECC to move in a more collaborative or clearinghouse and data clearinghouse-type approach; and we're pleased with the progress that's being made in that area.

The third and last area that I'll cover is trying to reach critical mass for these big projects that was referred to earlier as megaprojects. We think it's going to take some staging. And some of the corridor identification and work that the Department of Energy is doing we think will help facilitate that.

So as you go from a corridor to a footprint, perhaps we will have to look at some of

these projects like the one that Mr. Metague from PG&E articulated earlier, that in a staged way, so that we get the corridor established. And then maybe start building something that gets us a footprint. And then build on that so that if we want to integrate in a synergistic way with some of the other projects like Frontier or NorthernLights, that we can get to the doorstep as was referred to in the other earlier comments.

So, overall, we're encouraged. We are concerned, though, that there needs to be perhaps a little more stability in the state policy setting area. If we continue to have moving targets, whether it's for renewable policies or for greenhouse gases, it's a little bit harder to plan against and around those moving targets.

So with that I would be happy to answer any questions.

PRESIDING MEMBER PFANNENSTIEL: Questions? None, thank you.

MR. DeSHAZO: Good afternoon, Madam Chairman, Commissioners. Thank you for the opportunity to be here this afternoon. It sounds like this morning there was some very good discussion and conversation on transmission. And

during my time here this afternoon I certainly have heard a lot of good things that have been put on the table in front of us.

I guess with regard to the two questions, been giving this some thought here. The contributions of these, I guess of these projects in helping California achieve its overall goals, you know, with regard to greenhouse gas and the renewables, I think that at least what I heard from Mr. Sims and at least in my mind, it is something that I have said before, is that we are going to have to build more transmission into California from outside. We're going to have to increase our imports.

I think that I have made comments along the lines that, you know, of course, depending upon what kind of retirements that we have, what kind of new generation that shows up, what kind of load growth that we have, that over the next 25 to 30 years this could be 7000 to 10,000 megawatts of transmission needs in order to balance out the overall portfolio, to be able to serve the load that we have.

We know that given that we do have to increase our imports, you know, the ability of us

to be able to operate our system, given the renewables that we're proposing to place into service, are going to cause some difficulties for us in order to operate the system.

We know that just by 2010 you're talking about 4000 to 5000 more megawatts of generation in the wind, the Tehachapi area; plus the other solar and others that are being added. These bring some complexities, I think, to us as the operator of the system. And how do you manage 4000, 5000 or 6000 megawatts just showing up within a half an hour to an hour. It causes issues with ramping; it causes issues with regulation.

We also have, I think, as we add more and more of this generation you'll find, at least on the technical side, that the technical aspects of our system are going to change. You got different types of generation that are now connected to the system that have the quote mass and inertia that combustion turbines have or steam turbines have.

The system, I think, under conditions of faults, especially difficult faults or difficult disturbances, is going to start to respond a little differently than what we are used to

seeing.

I think overall we have reliability hurdles that are associated with these things. We have local capacity requirements. We have resource adequacy needs. And, then, of course the overall mandatory compliance for reliability that FERC and NERC are placing before us.

I believe, and I think we've heard this a couple of times in the presentations made this afternoon, that transmission projects of this type are ones that we need in order to be able to increase our imports to help us manage. One, to be able to utilize the renewable portfolios that we're planning on putting into place. And also to be able to provide us an opportunity to go after, or at least be able to get other types of generation from other parts of the country, or the western interconnection.

In terms of, I guess of the overall policies, the federal and the WECC trends and policies, if we're willing to accept that openness and transparency and coordination and stakeholder involvement are necessary to the success of being able to get the transmission built, then clearly in my mind that the efforts under the order 890,

as well as the WECC TEPPC, are a positive thing for us to be able to achieve those goals.

I think that there are key things that are associated with what is happening; that both the order 890 and the WECC TEPPC groups are bringing forward, clearly the transparency and the openness are key issues.

One of the things that I've learned a lot about since I've been in California is the stakeholder process. Stakeholders have, you know, I think specific needs; they're pretty straightforward. They don't like surprises. They don't like things that change without some knowledge that things are going to change.

I believe that they really want to understand what the end is going to be, and they want to participate in that process to be able to get there. And, in fact, and I think even further they want to be able -- they want to know that they're going to be able to participate in that process, that they can affect changes in where the end result is going to be.

Coordination, you know, also it's clearly a big part of this. That it has to be in place in order for any of this to be successful.

I think that order 890 brings before us, first of all, I think it's bringing all the parties to the table. It's not that the parties weren't there; the parties have always been there. But I think that the order 890 is sort of placing a different framework around how this is going to be done. And that, I think, is an extremely positive thing to do.

It's providing us the principles by which we need to move forward. This is something that's been somewhat lacking in the past.

What we're doing and where we're heading really isn't rocket science. I think this is commonsense. But various people represent various different interests and they have different ways of looking at the problem. And so if you don't have a way to put a framework about how we're supposed to approach that, then it can tend to be extremely difficult in order to be able to move forward with things.

I see that the work the WECC is doing through TEPPC as also being an extremely positive and important process. It's bringing focus on the subregional needs of the western interconnection. It's providing oversight to the overall concepts

of subregional planning.

There's, of course, the common database that's been placed on the table, which I think when we started with SSG-WI really has become such an important aspect of the things that we need to do. And certainly for the California ISO, and a lot of the work that we have done on economic projects, that data has just been significantly important, beneficial to us.

Overall for both sides, or at least both of these pieces, I think it brings focus to the fact that we need to have some type of organized subregional planning within California. I think that when given the chance that the stakeholders, if they're given an opportunity to participate in a process that's robust, that they will arrive, as a group, at the right solution.

And what we need to have is some type of framework, some type of process in place to provide them the opportunity to be able to participate in these processes so that we can at least drive ourselves to what we think is the right answer.

So, yes, I do believe that these things will help the state in achieving its overall

renewables portfolio goals.

ASSOCIATE MEMBER GEESMAN: Gary, I wonder if you could share with us your reaction to DOE designating virtually all of southern California a NIETC zone.

MR. DeSHAZO: Well, I think that my initial reaction is that is, as was said before, is a bit broad. I see that in terms of transmission planning we've always wanted to try to look far enough out. And we've always believed that it would be nice to identify a corridor upfront that we could rely on. And then maybe ten years later that we could come back and actually get something built in it without something preventing us from being able to do that.

I think, you know, if you talk to people throughout the western interconnection you're going to find numerous examples of where something like that would have been helpful.

I think we have to start someplace. I know that the Commission also sees value in corridor identification. But we need to start someplace. I think, at least in my mind, that DOE has made a start. It's not an easy thing to do considering all of the different interests that

are involved.

Is it useful to us at this point? It gives us maybe an area. But we really need some more focus on that.

ASSOCIATE MEMBER GEESMAN: Well, you know, the ISO's been in operation nine years now, and I take the DOE designation, I think, about the same way I would if my teenager brought home a report card with an F on it. And I think that, you know, just in the interests of sobriety state government ought to take it the same way.

You know, there's something wrong about a planning process that doesn't serve up enough projects; there's something wrong about a permitting process that can't issue the appropriate permits that would leave the DOE doing a nationwide search to conclude that southern California was one of two areas in the United States deserving of an F.

And sacrificing state sovereignty over land use decisions is a big, big, big deal in the constitutional world. And that's where we are. That's where we are.

So, you know, this Commission tends to be a little bit hard on the CPUC for the way they

discharge their responsibilities in the transmission planning and permitting area.

But I think in fairness it's a reflection on all of us that, you know, nine years after the creation of the ISO, 30 years after the creation of the Energy Commission, we got an F. And I personally have a view that that might help us wake up. But I recognize that people are moving to their designated corners and will come out swinging. And this is likely to be seen as just another federal power grab.

The reality is that congestion costs ratepayers in southern California hundreds of millions of dollars a year. And we've allowed ourselves to largely become inured to that.

Sorry for the sermon.

PRESIDING MEMBER PFANNENSTIEL: Gary, you commented that with the transmission needs that we're facing, I think you said we needed organized subregional planning forum or body. Does that -- that implies we don't have such a thing now? We don't have an organized subregional planning capability? What would that look like? And we have a lot of -- we've been hearing now about a lot of different planning capabilities.

What do we need?

MR. DeSHAZO: Yeah, I think that was probably a bit broad to imply that there's not organizational types of things that are being done within California, which is clearly not the case.

You know, I think pretty much everybody that's sitting at this table, and others in this room, all face off with one another at the WECC level in terms of coordinating the work that we do.

I think that in the context of where things are headed today, with what TEPPC is interested in doing with the western interconnection, and with what FERC is interested in seeing occur through order 890, that kind of thing does not exist yet today, I think, in an organized way within California.

I believe on the outside that we're viewed as being somewhat fractured. That there are, some would actually see that the state possibly should be bifurcated between north and south, suggests that northern California should maybe have more interest in line with Columbia grid; and southern California would have more interest in line with WestConnect.

And inherently that is not the right thing to do. I think for us that making decisions about how you build transmission into the state or out of the state is as much about how the transmission system inside the state is operated.

Simply because you've got a congested path, path 26, you know, to want to draw a line through that path and simply say that we can handle each one separately, I don't think is really the right approach.

I think that the right answer is what's the best thing for the California consumers and the California ratepayers. And clearly there's transmission investment that California needs to make. Regardless of who makes it, I think that if we can provide a forum for interested stakeholders, interested parties to be able to come and put their ideas on the table, and then try to coordinate that into what the right thing is to do.

It may not be the one that, you know, certain entities may want. But what's the right thing to do. If you can identify that, then you can take the time to try to figure out how to make it work.

MR. FEIDER: Madam Chair.

PRESIDING MEMBER PFANNENSTIEL: Yes.

MR. FEIDER: Could I address that question a little bit?

PRESIDING MEMBER PFANNENSTIEL: Of course.

MR. FEIDER: Jim Feider with TANC. It may be instructive to take a look at what's going on in other parts of the west when it comes to subregional planning.

The gentleman earlier from Arizona Public Service that talked about their major project, I don't think made much, if any, reference to the significant transmission investment that they've had to do in and around the Phoenix area for example, to keep the lights on.

And so I think when it comes to subregional transmission planning, where the rubber meets the road is the utility that's responsible for keeping the lights on will stimulate a lot of investment, whether it's transmission or generation, because in my role as Utility Director, I'm held accountable at home on the streets of Redding.

So, we're going to make the investment that it takes. It may be that California has a few too many players for accountability to really come home.

PRESIDING MEMBER PFANNENSTIEL: And that, in fact, may be. Any other questions for this panel? We want to thank you all; very very useful.

PRESIDING MEMBER BYRON: Thank you.

MR. McCLUSKEY: Would the second panel, the transmission project presenters, take their seats, please. And we can address the --

(Pause.)

MR. McCLUSKEY: We'll have these project presenters present or respond to the same set of questions that the first panel did concerning contributions to renewable resources and GHG goals for the state; and recent federal and WECC trends and policies regarding interstate planning.

Whatever order you're seated in. Steve, why don't you start off.

MR. ELLENBECKER: Thank you. Again, Steve Ellenbecker, Governor Dave Freudenthal's Office in Wyoming.

Please take this -- I'm going to turn

the question around -- please take this in the constructive spirit that it's meant, because I sincerely am reaching out for your expertise in California.

If Rob Hurles, my colleague in the Governor's Office, were here Wyoming's energy policy team would be here in total. So, I would encourage that as you develop public policy you consider ways in which you can reach out across the west and engage with us.

Because you bring such great expertise, including in sheer numbers, of resources and personnel that you can offer other states, as you select the path forward that you think is best suited for California. And I trust, in part, that implies that it is well suited for much of the west.

We need to be able, as we develop our strategy, Wyoming as an example is an energy-producing state, of which you do have the advantage of some of our resources, particularly natural gas, we want to work with you and need your expertise in working with us to develop solutions to your future energy needs. And therefore, solutions to the kind of products that

we can develop out of our natural resources and energy resources. Whether they be natural gas, advanced coal or renewable wind, that meets your public policy needs.

I was taken by the comment in the last panel about the need that we start to stabilize public policy around which then new generation resources and transmission can be built.

That was a request made of one of your panelists. And I think the west would benefit, the country would benefit, from a stabilization of public policy so that we know what our targets are that we're trying to achieve.

And then if you would work with us by bringing your resources and illustration like the great expertise that Bill Chamberlain of your staff brings to the Western Interstate Energy Board and his guidance on reliability. We need that kind of expertise from California in other states where we are so few in numbers of personnel.

Bob Smith mentioned three models that we're looking at for interstate transmission. Those promoted by a load-serving entity; the top-down approach that he was correct on that started

the FrontierLine concept, really it started back in the Rocky Mountain area transmission study.

I believe it has been accurate replaced now by load-serving entities and, potentially in the future, a combination of them, along with merchant developers.

I think we have it in the right sequence, but I'm proud that the governors and their staff did what they did, because I think it has encouraged the dialogue on interstate projects, and helped promote the discussion for the potential of these projects.

Bob is correct that it's the combination of public policy, load-serving entities, and merchant developers. I hope you continue to develop policy that promotes the success of all three models.

I think it's a matter of federal law to do so. Order 890, in my opinion, the way I read it and react to it is it's a statement and acknowledgement, speaking about acknowledgements of shortcomings, it's an acknowledgement by FERC that they have failed in opening up access to the interstate grid. It's their attempt to improve upon the openness and transparency of that access.

In my work with generation and project developers on the generation side, they would agree wholeheartedly that this open access grid is not yet as open to them as they would like to see. So, I hope you would support the work being done in order 890 to play a role in improving the access to the grid that exists across the west.

It troubles me a bit that TEPPC is cautionary to the point of not supporting projects. I think we have a wonderful opportunity to promote through the subregion transmission expansion planning groups that exist and will continue to exist and coordinate, as I have seen, closely with TEPPC, we have an opportunity here to really set the stage and facilitate the success of some of these interstate projects that have been spoken of in the panel that I'm a participant on.

I really hope that, to the extent it can, that TEPPC, in coordination with the subregion transmission expansion planning groups, and in cooperation with the states, work hard to help insure that many of the projects that were on the map that Jim Sims presented, indeed are built and go to construction sooner than later.

As it relates to greenhouse gas

standards, Wyoming and California have a partnership through the governors on supporting IGCC demonstration in Wyoming.

California, by active participation and support of developing advanced coal technologies, can unleash the continued sustainability of a very abundant western resource and available domestic supply.

And with the strength of your numbers, the power of your congressional delegation, the strength of the CEC and CPUC, there's an opportunity here for California to play a major role in helping the coal technology achieve the capture and sequestration requirements that are appropriately being set.

It's not a matter of whether we're going there, so it should be a matter of how can we work together to get there so that, indeed, this resource, too, is available across the west to meet growing public power needs and the requirement for electricity, in combination with efficiency, conservation and renewables.

So there should be a place for it. If we can get the technology curve advancement that we need, the implications are worldwide, because

if you can help us break through the commercialization, the application potential is not just for the west, or for a coal-fired power plant in Wyoming, the implication is that the technology can then be used elsewhere, not just in the U.S., elsewhere on the broadest scale.

And we need to move forward very quickly in that regard. California can make a major difference.

Greenhouse gas emission control and reduction is a major, clearly a major initiative in California. Why not most certainly help us with that major opportunity where the carbon emissions are so great. We need your support in that regard.

I plead with you to consider your good neighbors who are reaching out to California and ask that you reciprocate. We need your help, and in turn we believe we can be a part of the solution for your needs in a way that provides products that meet your public policy standards.

Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Mr. Ellenbecker. And just to note, I think that you know, and we probably all are aware, that

Californians and certainly the California Energy Commission is doing a lot on research on clean coal and sequestration. And we're putting money and effort into that.

And we share your desire to see coal being able to be cleaned up to a level that it meets California's requirements.

Questions?

Thank you.

MR. SMITH: Thank you, again. Bob Smith with APS. I wanted to, before I go to the questions, because I've got to be fairly brief, we've covered a lot of that.

I just wanted to pick up on Steve's concept of the stability of public policy in terms of resources. I thought about sort of a lead-in description of this panel, specifically the barriers and potential ways of overcoming those barriers for these transmission projects.

And certainly one of the huge ones surrounds resources in two areas. One is the, at least for some of us, inability to do the utility-based integrated resource planning that we could five, 15 years ago, for some of the FERC initiatives.

And maybe even moreso is this whole carbon policy issue. I, like Steve, would appreciate stability in those things, but I think it's probably a little too much to ask at this point. Because both these things are fairly new. And I think we're still working through them.

Certainly for our resource planning department assumptions have changed tremendously just in the last year. And the way we're viewing this TransWest Express project is quite different today than it was a year ago. The assumptions that are put into the resources at the end; how much wind would be there; how much coal; what kinds of coal; how it impacts the economics are just huge.

So, some of the things I think that can help overcome this, and I think you're doing some of these very very well in California, public stakeholder IRP processes. And whether it's state-based or regional-based, or done within the subregional planning groups, the point is get all the information out there, the best information and all the players, whether they're developers of generation or transmission can use to try and integrate things as much as possible.

And along those lines, the more that you or the FERC or any other state can incent generation developers to truly be transparent as much as possible, I realize it is a competitive business, but as much as possible in their planning be part of the regional and subregional planning processes.

And if there's any way you can incent them into being certain sooner, and more certain in their plans, that would be a wonderful thing.

The other thing, I think, that has been a barrier, and I think we would all agree with this, is just getting the right consortium together with the right needs that makes sense to actually kick one of these projects off; and get a group of folks that are actually motivated to put some significant dollars into funding the permitting.

And, again, I think we just need to be looking at ways to leverage the mutual benefit; have a willingness to be flexible. And the more we're getting these potential conceptual projects out into the subregional and regional planning forums, as early as possible in the process, I think we're all better off.

So, with that, you know, the first question here, I think we could probably look at the first couple of slides that Jim Sims offered us today, and it really says it all.

These transmission projects can bring increases in reliability for the entire system; it can lower losses; offer flexibility, diversity, opportunities to access renewable, particularly wind. I think it would facilitate the ability to remotely do things like regulate for the wind, so you can have more intermittent resources going into different parts of the region, different control areas.

I believe it will encourage the advancement of coal technologies. And ultimately I think -- I don't think any of us believe that the energy prices are going down. But maybe it will, in some way, mitigate the pressure on upward prices that we're going to be seeing in the future.

The second question might be a little more interesting, in that I think a lot of the initiatives that FERC has put forward over the last couple years certainly can help these projects and the states meet their energy policy

objectives.

Particularly some of the opportunities for transmission incentives. And we've had a lot of discussion at APS and amongst some of the other participants in our project, about, you know, what incentives would make sense for us.

And I believe there's really sort of two sets. One are incentives that help decrease the risk of the project. Things like guaranteed recovery of, you know, maybe even study costs that you're incurring before you have a specific project. Predevelopment costs. And in fact, earlier opportunities to recover expenses as you start spending them on the project. So that's sort of one area, minimizing risk.

The other area is the opportunity to get a higher rate of return, which is supposedly offsetting your higher risk. So they're probably sort of an exclusive set of incentives. And where we have tended to focus is the former. Things that will offset our risks.

And I really congratulate you on some of the things you're doing in the State of California to allow your utilities the opportunity to do the right thing. They're going to incur some costs in

doing that, but it may make sense to do that and allow them to recover those costs.

I've been a proponent for a number of years now of the earlier that we define projects, determine the best alternative, and actually get a permit for those projects, even if we don't know for sure when we're going to build them, but we have a pretty darn good idea we're going to need them some day, that could really take a project that most people think of as an eight-year project, and with the permit in hand you can go out and build a lot of transmission in two years. Which is more the timeframe it takes for some of these resources to be developed. Or time to maybe recover from, oops, we're in trouble two years down the road in terms of capacity.

So I think some of the things that the FERC has put forward are good. WECC really, and I've been involved in WECC for 12 years, it's all good. WECC is very very concerned about reliability, but over that period of time they've also gotten involved in open stakeholder process, really opening up the process to all the market participants.

And, of course, more recently, as Scott

talked to you about, they're actually doing expansion planning now, economic expansion planning. Yeah, they've said that they're not going to pick winners and losers, and I understand Steve's point there, but I do think that they will provide results from studies that will speak for themselves. So I'm not sure WECC has to stand up and, you know, jump up and down and say, yeah, TransWest is the answer. But I think a lot of the study results will, not necessarily TransWest, but provide the same type of information.

I think the subregional planning is very important. For the last tree years I've co-chaired the STEP group, which is on some maps it sort of looks like the California subregional planning group, but it's actually a group that was put together to help develop transmission between Arizona and Nevada into California.

And I think it certainly did a wonderful job and was very effective in doing that. But I also believe I've seen things over the last year or two that's very important for you to have a California subregional planning process that would fit very well into the WECC regional planning process.

And I guess I'll end with the only downside I see to all these things that are happening at FERC and WECC and everywhere else, are that -- this would be the hot topic if you were to sit around a table in the evening and listen to a bunch of transmission planners drinking, is that they're very pressed for time.

They are a rare breed. I think those at the table here will agree with that. The rest of you say we're a strange breed, but anyway there's a lot of pressures on the folks that really need to be doing the study work and actually doing the planning for these facilities. There's a lot of things that are really demanding of their time.

And so the next time you think about, you know, another meeting or another set of forums or another group that we all need to send someone to join, you might just reflect on that. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Mr. Smith. Other questions? Yes.

PRESIDING MEMBER BYRON: We'd much rather have you in a meeting than sit around listening to you drink.

(Laughter.)

PRESIDING MEMBER PFANNENSTIEL: Mr. Hosie.

MR. HOSIE: Thank you. I'd like to start off by saying that there's vast potential resources outside of California. Wyoming, Montana, Alberta, British Columbia are probably the largest resource areas, and there are others.

There's huge load growth in California and the southwest and the Pacific Northwest. And we at NorthernLights, TransCanada, are just a transmission company. We're just trying to connect generation to load and get everybody at the table at the same time.

And so on the Inland project we've heard frequently today about the opportunity to bring Wyoming and Montana coal-fired energy to California, to the south. And there's an incredible desire to build IGCC plants, gasification plants that can then capture the CO2 and sequester the CO2, so that we have near-zero emissions plants.

We believe a NorthernLights type of project, and the other projects here will facilitate that opportunity.

Another big opportunity is the

integration of the wind. Making wind work is not just a matter of hooking it up to a grid. But there's also the opportunity to take wind over vast geographic differences and integrate them in a way that the capacity factor of the wind is substantially increased. And long projects like ours do facilitate that integration. And being able to depend on the wind more than if it's just local.

With dc technology, you also have the opportunity to control the power systems instantaneously so you can manage the power flows over the transmission system. And mitigate the issues of wind integration that many people have found out about.

At the same time what we would like to be able to do is to encourage generation developers to develop generation that has some component of controllability, dispatchability so that they would also be able to contribute to the integration of wind.

Then in these states, Montana, Wyoming and Idaho there's huge geothermal potential. We think that the NorthernLights Inland project will provide access to that energy.

Switching to the Celilo project, Alberta's going through a huge transformation. And it's primarily driven by the needs of the U.S. market for increasing oil supplies. Alberta's got about $150 billion worth of oil sands extraction and upgrading projects going ahead. We've moved from one million barrels per day in production to, by the end of the decade we'll be at 2 million. And shortly after that we'll be at 3 million barrels per day of oil, virtually all destined to come down to the United States.

And there are concerns in the oil sands area of the CO2 emissions that we have there. the first gasification unit that takes the waste products from the oil sands, products that would just be stockpiled, is going into service this summer. The gas turbines are in, already working on natural gas. A 1000 megawatt thermal gasifier is going into service this year. And the output from that gasifier will be used to drive gas turbines. That makes it relatively easy to capture the CO2.

A second gasifier of that size is being applied for for inservice in 2012. If the project that are on the books in Alberta go ahead, Alberta

will have about 20 percent of the new gasification projects in the world.

But there's more happening. The Alberta Government has initiated integrated energy vision that wants to maximize the efficiency of energy capture through cogeneration, is the obvious outcome of that. They want to minimize emission intensities and have started off with a $15 per ton charge for those who haven't reduced their emissions by 20 percent by this July. So the charges go into effect and the revenue from that will go into a technology fund to help move ahead the CO2 reduction targets.

TransCanada -- well, part of that energy vision is that there be a mechanism for capturing the CO2 emissions. And so TransCanada is moving ahead with a comprehensive plan for capturing the CO2; pipelining it down to areas where it can be sequestered and hopefully used for enhanced oil recovery.

So, Alberta is going through tremendous changes in that way. And we also are developing a hydro plant, a new hydro plant that would be environmentally benign that could be up to 1800 megawatts of capacity, run-of-river about 60

percent capacity factor.

We have vast coal resources that are yet untapped. We are at 400 megawatts of wind this year; next year we'll be at 900 megawatts. And the Alberta ISO has set the limit at 900 because of regulation issues. So we believe the NorthernLights project can tap into all of those types of resources and break the roadblock for the integration of wind out of Alberta.

That, coupled with integrating the Alberta market, we believe that this and the resources I've talked about, we believe that would be a substantial benefit to California. Whether we're on the doorstep or whether we extend it down into California.

So, bottomline is that NorthernLights is committed to tapping Alberta resources, B.C. resources, resources from Montana and Wyoming on all of the different, all the three different projects.

Around the WECC, we're a real believer in the benefits of the WECC. We see the continuation of the segue work to be hugely beneficial and essential to moving a project like ours, or the others, ahead.

The planning coordination role that the WECC plays is very significant. And without it, I don't see that we could move ahead.

One great example of the work that they've done is the 1221 DOE congestion study. It was an outstanding piece of work. And the WECC has a huge influence over NERC and FERC and protection of western deference. The western system is different and needs to be managed differently than the eastern system. So, we're very high on WECC and will continue to be so.

On the federal front we see that the section 368 process has been quite meaningful. We see that a number of corridors will be established. Some very very long corridors. There will be some aspects of our projects will be easier to permit, but there will be pressure for deviations from the corridors. And we've identified shortcuts that we'll want to take from the corridors, and believe that the land use agencies will be receptive to those shortcuts.

So it's not a silver bullet, but is very very helpful.

We think the 1221 process has probably contributed the most just by perhaps making some

jurisdictions mad, making people pay attention that if they don't get on with revisions to their processes they'll be taken away from them.

We're averse to getting into trying to declare a NIETC because we don't think that in the end it'll work out effectively, especially if you're the first and you have to go to the supreme court to work out the details. We don't see that as being beneficial at all.

And the one other thing that's worth mentioning is the Western Governors siting protocol. We see that as being a very powerful tool for helping to coordinate projects that cut across several states.

So those are my comments.

PRESIDING MEMBER PFANNENSTIEL: Very good. Questions?

Mr. Metague.

MR. METAGUE: Thank you. I have the honor of being last, and a lot of the comments that I would have covered have already been covered, so I'll keep it relatively brief.

Let me address the first question, and not surprisingly I think that the project that I've come to speak about today is a perfect

complement for renewable portfolio standards, greenhouse gas goals that the state has set as policy.

And, in fact, I almost flip the look by saying that in some respects state policy has been what has inspired this project. So we think there's a very natural complement there.

Moving on to both the FERC and the WECC, let me start first with -- I'm sorry, with the federal policy. Let me start with the Federal Energy Policy Act, which I think was very very important in recognizing the need for spurring transmission developments throughout the United States. I think it's one of the elements that has helped make the stars aligned in a much better way than I've seen in many years for the development of regional projects that we are all working on here today.

I think the FERC role there, I would like to talk a little bit about. Bob Smith started to mention it, order 679, and both the incentives for the development of transmission, I think, have been helpful, and the, I'd just call it the flexibility that the FERC has shown in terms of recovery of costs associated with these

projects. I think that's a very helpful element.

Also, I think, you know, the siting issues, I think I just, in summary, would like to say that one of the benefits, I think, of the National Energy Policy Act, and we're seeing it in some of the discussion today, is that each of the states seems to be very attentive to making sure that their processes are supportive of large projects. I'm seeing that as I talk to siting officials in Washington, Oregon and I believe here today in California.

Let me also address the WECC and just make a couple of points there. I think the WECC has some very very good processes. As I mentioned earlier in my remarks, the NTAC subregional planning was really a natural predecessor to the kind of project that we have picked up.

It really was creating a natural bridge doing the original work to look at what might make sense in terms of a project. And then looking for a sponsor to take over. And that's what we have done, we and the other utilities who were involved in this project, have become sponsors to take the work initially done by the NTAC and move it to the next stage.

I'd also like to commend the WECC process in terms of the flexibility it allows. All of the individuals at this table have started their regional review process in a slightly different way, which presumably fit their project best.

We were the first to do it. I mean that was one of our first steps, to announce our project. We felt that that process which opened up a stakeholder -- basically allowed stakeholders to come in, follow the intent of order 890, and allowed us to get our project really kick-started was very valuable. And it came very early; it was the first thing we did, and I think that's appropriate, at least for our project. It made a lot of sense.

The one other WECC thing that I would like to mention is the path-rating process. And in some respects it goes to the property rights issue. On the ac system it's very very important for anyone who's looking at a transmission project to have some confidence that the transfer capability of that project will have some durability in time.

And the path-rating process at the WECC

is very valuable in that regard. And I comment it. I think it is one of the things that has been in place for many years, but is very very supportive of projects like we're talking about today.

So, in total, I'd say that I'm very very pleased with what I'm seeing with both state and federal policy. I think it's very supportive of the kinds of projects that we're seeing here today, and the project that I'm particularly advocating, which is this transmission line to Canada.

So, with that, I conclude my remarks and thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Steve. Are there questions?

Well, I want to thank this panel. It's been a useful, and I think provocative discussion. So, thank you.

Before I adjourn though, let me see if there are public comment here? Yes. Jane.

MS. TURNBULL: Chairman and Commissioners and Staff, I'm Jane Turnbull of the League of Women Voters. I just have a couple quick comments.

The League is here as a stakeholder. And I want to pay particular commendation to Jim Sims' emphasis on public education, because I think that is a very real challenge. And it's something that the League has been working on, with only a limited amount of success. Because these issues are complicated and the public really, in many cases, doesn't want to know about them.

But I'm really glad that Joe Eto brought up the topic of the transmission system as a public good. Because I think the public needs to come to understand that. And also understand that there is societal value to it. And how you recognize that societal value in a tangible way, I think, is a very interesting challenge.

I also would like to say that the League strongly supports regional and subregional planning. We think it needs to be done at the time that a need begins to become identified, not when it is well along, and not when the siting process is well along.

I hear from our San Diego members at least daily about the Sunrise Power Link line. They were very unhappy because it was all in place

before the public had a role in even understanding the need.

And the amount of emotion that has been generated by that is really exhausting. It tires me out just having to read these emails every day.

So, you know, I do suggest that the process begin at the earliest stages, and that the stakeholders become involved early on and understand what's going on.

One other point; I'd like to comment the PIER program for their support of the PACT project. I've been on the steering committee for that. This is the modeling effort to model alternative transmission corridors, and to value, to put, you know, different values on different criteria, and begin to do tradeoffs in a very powerful way. That's an extremely valuable tool, and I think if the public has a chance to get an understanding of how the planning decisions are made and what the tradeoffs are, we'll be in much better shape.

Thank you.

ASSOCIATE MEMBER GEESMAN: Question.

PRESIDING MEMBER PFANNENSTIEL: Yes, Commissioner Geesman.

ASSOCIATE MEMBER GEESMAN: Jane, just a followup on your comment about public goods. Do you have a view as to the appropriateness of using social discount rates in measuring costs and benefits associated with public goods? That was part of Joe's slide, as well.

MS. TURNBULL: Right. And I personally like the idea. I just don't know how that's going to -- how successful that's going to be in getting the general public to understand the fact that transmission is a social good.

ASSOCIATE MEMBER GEESMAN: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Jim, did you have any final housekeeping issues?

MR. McCLUSKEY: No. The only thing I wanted to do was to thank these folks for coming, in most cases, such a long distance to join us in this panel and this overview.

Steve, thanks for coming from San Francisco.

(Laughter.)

PRESIDING MEMBER PFANNENSTIEL: Commissioner Byron.

PRESIDING MEMBER BYRON: Thank you, Madam Chairman. I, too, want to add my thanks to

the staff for pulling together, I think, a very informing workshop that mostly all of you to be here today and provide your insight. It's very helpful to us.

And, Madam Chair, also I'd like to thank my colleague, Commissioner Geesman, who's not in very good humor today, which is an indication that he's not feeling very well. Thank you for being here, John.

PRESIDING MEMBER PFANNENSTIEL: Comments? Commissioner Geesman.

ASSOCIATE MEMBER GEESMAN: I thought it was a very good workshop and I certainly thank all of you for contributing to it.

PRESIDING MEMBER PFANNENSTIEL: I add my thanks to the participants and to the staff who put it together. It was very helpful to us.

So, with that, if nothing further, we'll be adjourned.

(Whereupon, at 4:34 p.m., the Joint Committee Workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Joint Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 18th day of May, 2007.